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Flue Gas Desulfurization Using Fly Ash Alkali Derived from Western Coals

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FLUE GAS DESULFURIZATION USING FLY ASH ALKALI DERIVED FROM WESTERN COALS

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16. ABSTRACT: The report gives results of tests investigating the use of Western coal fly ash for scrubbing SO2 from powerplant flue gas, on a 130-acfm pilot scrubber at the Grand Forks (ND) Energy Research Center and on a 5000-acfm pilot scrubber at the Milton R. Young Generating Station (Center, ND). Tests of the 130-acfm unit were designed to investigate the effects of increased sodium concentration on SO2 removal and rate of scaling. Parameters investigated included liquid-to-gas ratios (L/G), stoichiometric ratios (CaO/SO2), and sodium concentration. Results indicate increased SO2 removal and decreased rate of scaling as sodium concentration increases. Tests of the 5000-acfm unit generated design and operating data for a full-scale 450 MW fly ash alkali scrubber to be constructed at the same Station. Results indicate that sufficient SO2 can be removed to meet NSPS requirements, using only fly ash alkali when burning 0.75% sulfur lignite. An 8-week reliability test was also performed. Fly ash alkali scrubbing tests of flue gas SO2 were also performed, using a subbituminous-derived fly ash and other various lignite-derived fly ashes. A detailed analysis is presented of capital investment and operating costs for 100, 500, and 1000 MW scrubbers using the fly ash alkali process.

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FOREWORD

New coal burning electric generating stations are required to limit their emissions of sulfur dioxide in order to protect public health. Many Western U.S. coals, although low in sulfur, still require some measure of sulfur dioxide control in order to comply with the New Source Performance Standard of 1.2 lb SO_2/MM Btu.

The mineral matter in lignite and Western subbituminous coals generally contains a high proportion of alkaline constituents, which will react in a wet scrubber to remove sulfur dioxide from the stack gas and produce a sulfate enriched ash sludge. This process, as described in the present report, has advantages of lower cost and improved reliability compared with state-of-the-art lime/limestone scrubbing. Ash-alkali scrubbing for sulfur dioxide removal can be expected to be widely applied to future boilers burning Western coals.

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Director, Grand Forks Energy
Research Center

ABSTRACT

A test program investigating the use of Western coal fly ash for scrubbing SO_2 from powerplant flue gas was conducted on a 130-scfm pilot scrubber at the Grand Forks Energy Research Center, Grand Forks, North Dakota, and on a 5000-acfm pilot scrubber at the Milton R. Young Generating Station, Center, North Dakota.

Experiments conducted on the 130-scfm pilot scrubber were designed to investigate the effects of increased sodium concentration on SO_2 removal and rate of scale formation. Parameters investigated include liquid-to-gas ratios (L/G), stoichiometric ratios (CaO/SO_2), and sodium concentration. Results indicate increased SO_2 removal and decreased rate of scale formation as sodium concentration increases.

Experiments conducted on the 5000-acfm pilot scrubber generated design and operating data for a full-scale 450 MW fly ash alkali scrubber to be constructed at the Milton R. Young Station. Results indicate that sufficient SO_2 can be removed to meet NSPS requirements using only fly ash alkali when burning 0.75 pct sulfur lignite. An eight-week reliability test was also performed. Test programs on fly ash alkali scrubbing of flue gas SO_2 using a subbituminous-derived fly ash and other various lignite-derived fly ashes were also performed.

A detailed analysis of capital investment and operating cost for a 100 MW, 500 MW, and a 1000 MW scrubber using the fly ash alkali process is presented.

CONVERSION TABLE

EPA policy is to express all measurements in Agency documents in metric units. Implementing this practice results in difficulty in clarity, therefore, conversion factors for non-metric units used in this document are as follows:

British	Metric
1 acre	4047 square meters
1 British thermal unit per pound	2.235 Joules per gram
1 foot	0.3048 meter
1 cubic foot per minute	28.316 liters
1 inch	2.54 centimeters
1 gallon	3.785 liters
1 pound	0.454 kilogram
1 mile	1.609 kilometers
1 ton (short)	0.9072 metric tons
1 part per million	1 milligram per liter (equivalent)
1 pound per square inch	0.0703 kilogram per square centimeter
1 cubic yard	0.7641 cubic meter
1 grain per cubic foot	2.29 gram per cubic meter

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The information presented in this report on the 5000-acfm scrubber was derived from a test program conducted under the direction of a steering committee comprised of the authors, Mr. Lloyd Hillier, and Mr. Ken Vig of the Square Butte Electric Cooperative, Mr. Dennis Van Tassel of the Minnesota Power and Light Company, and Dr. Fred Murad of Combustion Equipment Associates.

The steering committee wishes to express its appreciation to Mr. Phil Richmond of Square Butte Electric Cooperative, Mr. Cabot Thunem of the Grand Forks Energy Research Center, ERDA, and Mr. D. Mehta of Combustion Equipment Associates, for their supervision of the operation of the 5000-acfm pilot scrubber. Appreciation is also extended to Mr. Larry Woodland of Arthur D. Little, Inc., and Mr. D.A. Burbank of the Bechtel Corporation, for their technical assistance, and to the York Research Corporation and the Grand Forks Energy Research Center for the analytical work performed during the test program.

SECTION 1

CONCLUSIONS

Experiments at the Grand Forks Energy Research Center on a 130-scfm[1/] pilot scrubber investigating the effects of a scrubber solution containing high concentrations of sodium and low levels of suspended solids have shown that:

- The rate of scale formation decreased as the sodium level increased.
- Settling of the fly ash sludge degraded with increasing ionic strength.
- An increase in the level of total dissolved solids did not have a significant effect on sulfur dioxide removal under the conditions investigated. Other tests conducted previous to and after the tests currently reported have indicated a substantial increase in sulfur dioxide removal with increased sodium concentration under suitable conditions (1)[2/]

Experiments on the 5000-acfm pilot scrubber have been underway for one year, and the initial objective of confirming design parameters for a 450 MW commercial unit to operate on cyclone-fired lignite fly ash have been met. Variable studies are continuing under the Energy Research and Development Administration. The conclusions reached thus far are as follows:

- Sufficient fly ash alkali can be reacted in a wet scrubber to reduce sulfur dioxide in flue gas below the Federal emission standard when burning lignite with an average sulfur content of 0.75 pct in a cyclone-fired boiler.
- Up to 66 pct of the alkali used in a wet scrubber must be added as supplemental lime to reduce sulfur dioxide in flue gas below the Federal emission standard when burning lignite with a worst case sulfur content of 1.3 pct in a cyclone-fired boiler.
- The utilization of the alkali in the fly ash is reduced when supplementary lime is added.

1/ Non-metric to metric conversion factors are shown on page iv.

2/ Underlined numbers in parentheses refer to items in the list of references at the end of this report.

- Calcium sulfite scaling could not be detected under normal operating conditions.
- Calcium sulfate scaling could not be detected under normal operating conditions.

SECTION 2

INTRODUCTION

The Western reserve base for measured and indicated coal in place, as defined by the U.S. Bureau of Mines, totals about 216 billion tons (2). During the last 15 years, the Western share of U.S. coal production has risen from about 6 pct to about 18 pct. A national goal of one billion tons of coal production has been set for 1985, and about 30 pct of it is expected to come from the Western coal reserves. Part of this expanded coal production is anticipated to be used in gasification and liquefaction plants; a considerable portion would be used in the generation of electricity. Most Western coals require some control of sulfur oxide emissions to meet the NSPS, and stack gas cleaning technology for burning Western coals will assume much greater importance in the future than in the past.

The Western coal reserves include lignite, subbituminous, and bituminous coal, with the lower rank coals predominating. An important property of most Western coals is that they contain far less sulfur than the 2 to 3 pct sulfur content of a typical Eastern or Central coal. The sulfur content of Western coals averages about 0.7 pct and an average sulfur dioxide removal of only 30 to 40 pct is required to meet the Federal standard of 1.2 lb SO_2/MM Btu. Since the Federal standard is based on heat release, variations in heating value according to rank have an important effect on the coal sulfur content that is equivalent to the Federal emission standard, as shown in Table 1.

TABLE 1. COAL SULFUR CONTENT EQUAL TO FEDERAL EMISSION STANDARD

Coal	Higher heating value Btu/lb	Coal sulfur equal to 1.2 lb SO_2/MM Btu pct
North Dakota lignite	6,800	0.41
Montana subbituminous	8,600	0.52
Arizona bituminous	11,000	0.66

The required sulfur oxide removal efficiencies are determined by coal sulfur content, and emission limits established by State and Federal legislation. Retention of sulfur oxides on ash during combustion may lower the actual sulfur dioxide emission by 10 to 40 pct for lignites (3), but because of its variability, this effect does not guarantee compliance with the Federal emission standard. The removal efficiencies as a function of sulfur dioxide emission standards are illustrated in Figure 1. While the 0.7 pct average sulfur content in Western coals does not meet the Federal standard, it does make flue gas desulfurization potentially easier to achieve.

The ash content of Western coals can vary greatly, with the 4 to 20 pct shown in Table 2 representative of the overall range. The ash content and analysis can vary significantly between mines, and even between locations within mines. The quantity of fly ash in the stack gas depends on boiler design as well as coal ash content. The fly ash in the flue gas from a pulverized coal-fired boiler represents approximately 80 pct of the coal ash. Resulting particulate loadings are typically 2 to 10 gr/scfd. For a cyclone coal-fired boiler, fly ash leaving the boiler represents about 40 pct of the coal ash. The corresponding particulate loadings are typically 1 to 5 gr/scfd.

An important characteristic of most Western coal ashes is their high content of calcium oxide, magnesium oxide, and sodium oxide, as shown in Table 2. The alkali content tends to be highest in lignite, and progressively less in subbituminous and bituminous coals. As with coal ash content, the alkali content in Western coal ash varies widely, from under 10 pct to over 50 pct of the ash, with significant variations occurring within individual mines.

The first studies on utilizing the alkali in Western fly ashes were begun at the GFERC in 1970. The fly ash alkali, particularly the calcium oxide, provides an alternate reagent to conventional lime/limestone flue gas desulfurization. Laboratory tests at GFERC have shown that the calcium available is a function of pH and reaction time (see Figure 2). The calcium leached from the fly ash reacts to remove sulfur oxides in a scrubber system. A guide in assessing the importance of the alkali in Western coal is the mole ratio of fly ash alkali to coal sulfur. For a coal containing 7.5 pct ash, and 20 pct calcium oxide (CaO) in the ash, the calcium is chemically equivalent to slightly more than 120 pct of a 0.7 pct sulfur content. For some lignites, the total alkali-to-sulfur mole ratio may be several hundred percent. Thus, in a powerplant burning Western coal, there is often ample fly ash alkali to interact with sulfur oxides in a wet scrubber.

The present study reports on a continuing test program on fly ash alkali utilization using an in-house 130-scfm pilot scrubber, and a 5000-acfm pilot scrubber. Methods for the control of scaling are also discussed.

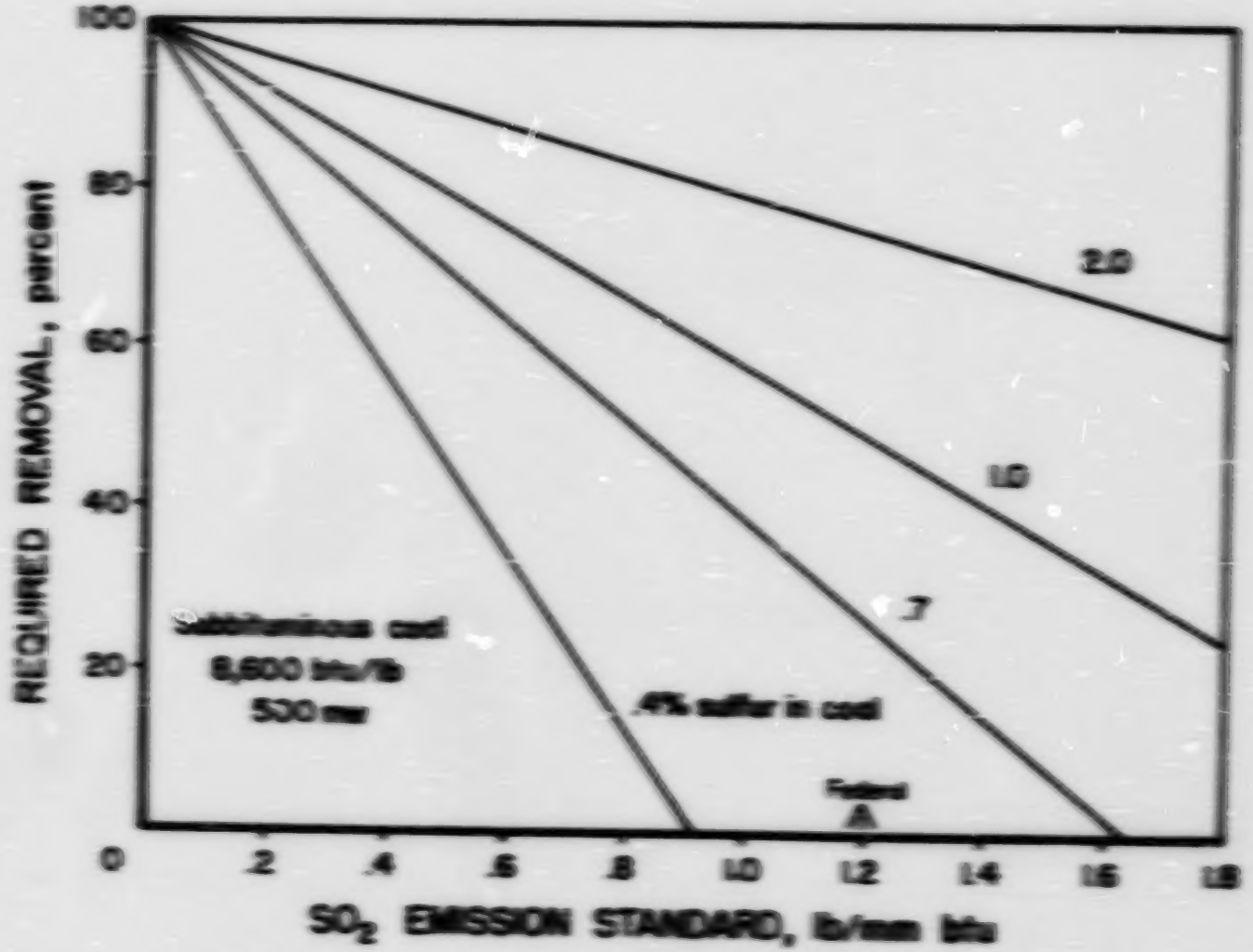

Figure 1. Sulfur dioxide removal efficiencies required for stack gas cleaning of Western coal.

TABLE 2. [illegible]

Coal	Lignite	Subbituminous			Bituminous		
State	North Dakota	Montana	Wyoming	New Mexico	New Mexico	Arizona	Colorado
Mine			Big Horn	Navajo	McKinley	Black Mesa	Hawks Nest
Sample avg.	232	135	12	2	1	1	3
			Ash, percent of coal				
	6.2	9.3	4.8	28.2	6.2	7.5	5.4
			Oxide constituents, percent of ash				
SiO_2	19.7	35.5	21.4	55.6	54.7	42.0	48.8
Al_2O_3	11.1	18.7	12.7	26.2	21.6	18.1	28.3
Fe_2O_3	6.1	7.8	13.9	6.1	7.0	5.7	11.5
TiO_2	0.4	0.7	0.6	0.6	1.0	0.9	0.8
P_2O_5	0.3	0.3	0.5	0.5	0.0	0.6	0.7
CaO	24.6	15.6	16.6	3.9	6.5	17.8	5.6
MgO	6.3	3.4	5.5	0.8	1.2	2.4	1.9
K_2O	0.5	1.7	2.2	1.5	1.6	1.4	0.6
Na_2O	0.4	0.4	0.5	0.6	0.8	0.3	0.5
SO_3	19.5	13.4	17.0	3.2	5.8	8.2	4.0

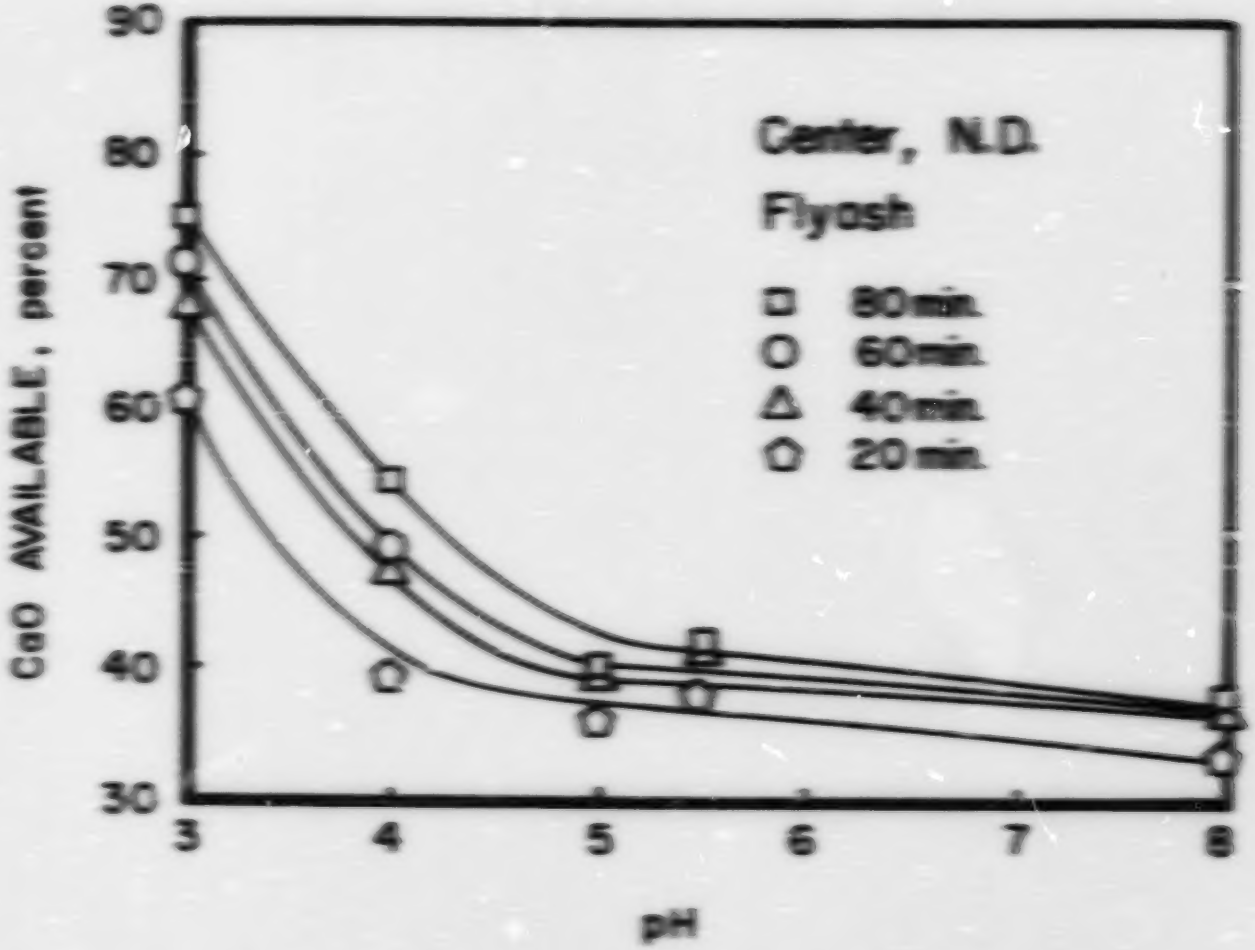

Figure 2. Effect of pH and reaction time on fly ash CaO availability.

SECTION 3

SUMMARY

GFERC TEST PROGRAM

The Energy Research and Development Administration at their Grand Forks Energy Research Center (GFERC) has investigated the fly ash alkali sulfur dioxide scrubbing system since 1970. Testing has been performed on a 130-scfm pilot scrubber. The principal objectives have been to determine sulfur dioxide removal efficiencies and calcium sulfate scaling rates as a function of sulfur dioxide level, fly ash add rate, alkali in the fly ash, supplementary lime requirements, level of recirculated suspended solids, liquid-to-gas ratio, amount of makeup water and total dissolved solids. Past results have been published in three previous papers (5,6,7).

The present GFERC scrubber (Figure 3) is a 130-scfm flooded disk venturi followed by an absorption tower containing conical "rain and drain" trays. Pressure drop across the scrubber can be controlled by adjusting the height of the flooded disk. The conical trays were installed as a modification to increase the liquid-to-gas contact time. It was believed that this modification would eliminate the gas-to-liquid transfer step as a controlling variable at high removal levels so that the observed sulfur dioxide removal would be primarily a function of the fly ash and solution characteristics and not of scrubber design. Installation of the conical "rain and drain" trays increased the removal efficiency by 5 pct, from 83.3 to 88.1 pct, under identical operating conditions.

The GFERC scrubber system is "closed loop." The recirculated scrubber liquor lost from the system as liquor in sludge, or as mist, is equivalent to about 0.8 acre-ft/MW/yr. Efficient mist elimination has been accomplished by passing gas through both a cyclone and a stainless steel wire mesh. Water lost by evaporation from mix tanks was replaced. Liquor from the scrubber was returned to a series of two fly ash mix tanks equipped with overflow weirs. The overflow from the second mix tank flowed to a settling tank where calcium sulfate precipitate and unreacted fly ash were allowed to settle. A floating overflow weir in the settling tank provided the scrubbing liquid to the flooded disk.

Early experiments at GFERC indicated that a large increase in total dissolved solids, primarily sodium and magnesium sulfates, experienced during the approach to steady state operating conditions significantly increased the scrubbing efficiency. Since the fly ash derived from some Western coals, particularly some lignites, are known to contain significant amounts of soluble sodium and magnesium, it is probable that high concentra-

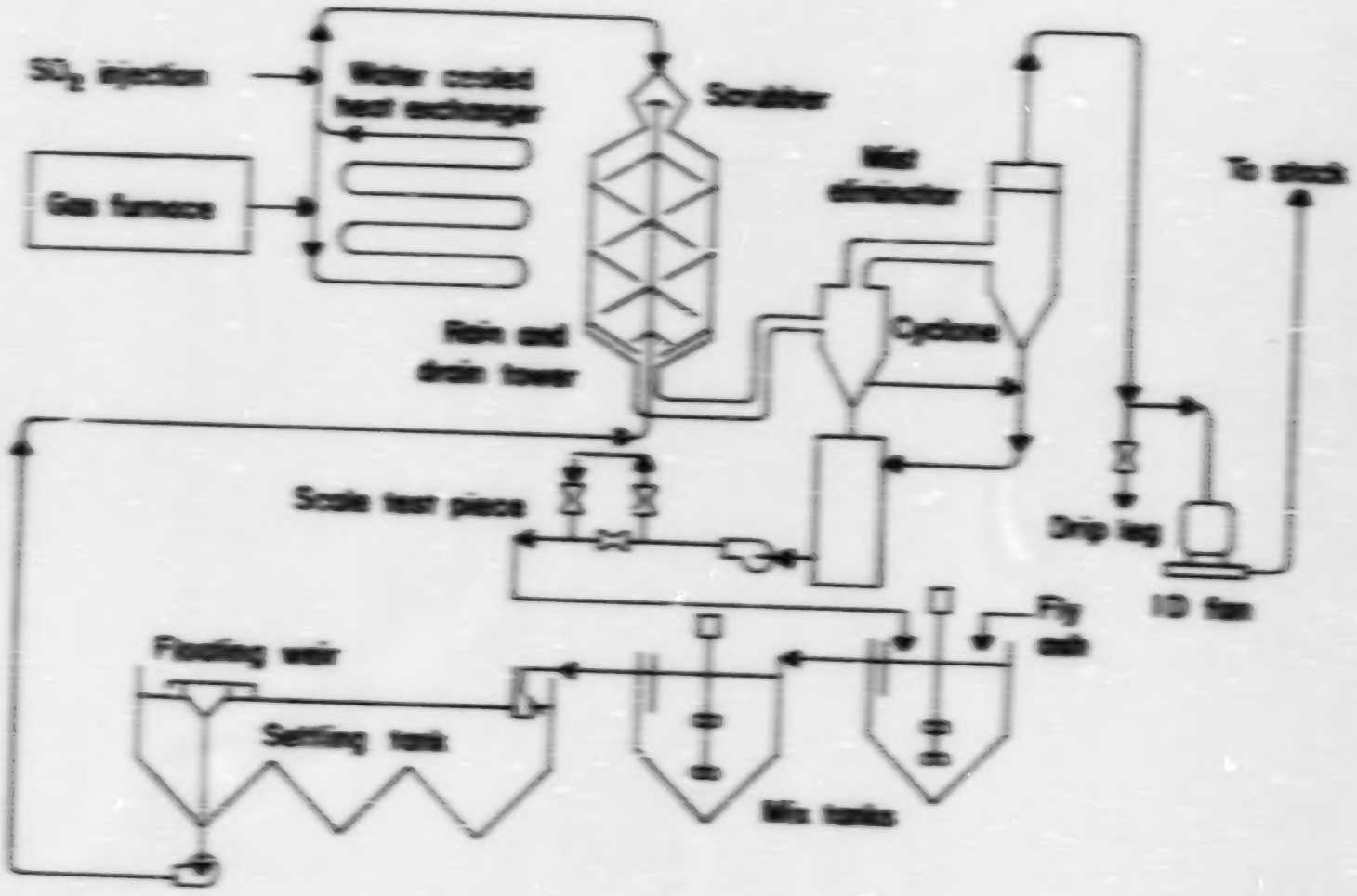

Figure 1. 150-scfm pilot plant scrubber, Grand Forks Energy Research Center

tions of these species will result after long-term operation of a full-scale scrubber employing the fly ash alkali scrubbing process. The current experiments at OFRC were designed to investigate the properties of scrubber solutions that are high in sodium (0.5 to 10 pct) and magnesium (0.5 to 10 pct). The objectives of the tests were to determine sulfur dioxide removal and scaling rate using a solution concentrated in sodium and magnesium and low in suspended solids (high levels of suspended solids, 6 to 12 pct, are common practice for scale control in some Western scrubbers). The fly ash used in these tests contained high sodium and magnesium and was produced by co-firing of Beulah, North Dakota lignite. Scrubber operating conditions kept constant for all test runs were: inlet sulfur dioxide level of about 840 ppm (typical of a Western lignite containing about 0.8 pct sulfur), inlet flue gas temperature of 350° F, liquid temperature of about 120° F, absorber tower pressure drop of about 13 inches of water.

Scaling rates reported represent the rate of weight increase in grams per hour observed in a 3 ft 4-inch length of 1/2-inch I.D. pipe in the return line from the scrubber to the mix tanks. The test position chosen was a point of maximum scaling, and trends in the observed values were found to be well correlated with operating variables.

Tests were performed at liquid-to-gas ratios of 23, 45, and 75 gal/1000 scf. The CaO/SO$_2$ stoichiometric ratio, based on inlet SO$_2$, was maintained at 1.2, sodium concentration at about 3.0 pct, and magnesium concentration at 1 to 2 pct. The pH of the liquor pumped to the absorber tower varied from 6.0 to 6.5; pH of the liquor exiting the absorber tower varied from 4.5 to 5.0. Previous experiments indicated only a marginal effect when L/G was increased, however, under the conditions of high sodium and magnesium, removal efficiencies were affected very significantly. The removal efficiencies and fly ash alkali utilizations are tabulated in Table 3.

TABLE 3. SULFUR DIOXIDE REMOVAL EFFICIENCIES AND FLY ASH ALKALI UTILIZATION AS A FUNCTION OF L/G. CaO/SO$_2$ = 1.2*

L/G	Removal efficiency (pct)	Alkali utilization based on CaO (pct)
23	81.0	66
45	88.2	72
75	98.1	80

* Stoichiometric mole ratio based on inlet sulfur dioxide level of 840 ppm.

The stoichiometric ratios of calcium oxide to sulfur dioxide investigated were 0.6, 1.2 and 2.0. These ratios correspond to particulate loadings of 2.0 gr/scf, 4.0 gr/scf and 6.7 gr/scf. Operating conditions were as described above, with an L/G of 45. The sulfur dioxide removal efficiency, fly ash alkali utilization, and scaling rate are tabulated in Table 4.

TABLE 4. SULFUR DIOXIDE REMOVAL EFFICIENCIES, FLY ASH ALKALI UTILIZATION AND SCALING RATE AS A FUNCTION OF CaO/SO2 STOICHIOMETRIC RATIO, L/G = 45

Particulate loading (gr/scf)	CaO/SO2*	Removal efficiency (pct)	Alkali utilization based on CaO (pct)	Scaling rate (gm/hr)	Suspended solids (pct)
2.0	0.6	63.3	100.0	1.68	0.13
4.0	1.2	88.2	72.0	2.7	0.18
6.7	2.0	96.0	49.1	3.0	0.24

* Stoichiometric mole ratio based on inlet sulfur dioxide concentration of 840 ppm.

In the above tests, some difficulty was experienced in removing the suspended solids to produce a "clear" liquid, even with the addition of sodium aluminate to the scrubber solution as a coagulant. The scaling rate of 1.68 gm/hr was observed at a suspended solids concentration of 0.13 pct, 2.7 gm/hr at 0.18 pct, and 3.0 gm/hr at 0.24 pct. Previous experience has shown that 10 gm/hr is a high scaling rate, and 0.2 gm/hr is a low scaling rate.

After the foregoing tests, the absorber tower was again modified, this time for the purpose of providing greater control of the pressure drop under conditions of severe scaling. The change involved attaching one set of cones, those directing flow from the center outward, to the standpipe of the flooded disk (see Figure 3). Thereafter, movement of the standpipe varied the spacing between the convex and concave conical trays as well as the spacing of the flooded disk venturi. Thus, as scale buildup occurred on opposed surfaces, all such surfaces could be moved further apart to maintain a constant pressure drop. A further effect of the change was to distribute the pressure drop more evenly throughout the scrubber tower. This last effect was believed to be responsible for a further increase observed in scrubber efficiency, from 88.2 to 92.9 pct, which probably occurred because of a more efficient use of energy in redispersing droplets of scrubber liquor throughout the tower. All of the removal data given below are offset from former data due to this increased efficiency.

Scaling rates and removal efficiencies were next investigated as a function of sodium concentration. The sodium levels investigated were 0.17 pct, 0.66 pct, 4 pct, and 9.3 pct. The 0.17 pct represents soc m leached from the fly ash during a 3-day test period; no make-up sodium was added. The magnesium concentration was kept constant at 1 to 2 pct, L/G was 45, calcium oxide to sulfur dioxide stoichiometric ratio was 1.2, and other

operating conditions were as described previously. The results are tabulated in Table 5. A typical solution analysis at each sodium level is listed in Table 6.

TABLE 5. SULFUR DIOXIDE REMOVAL AND SCALING RATE AS A FUNCTION OF SODIUM CONCENTRATION, CaO/SO_2 = 1.5,* L/G = 45

Sodium concentration (pct)	SO_2 Removal efficiency (pct)	Scaling rate (gm/hr)	Suspended solids (pct)
0.17	95.2	5.8	0.066
0.66	92.9	3.51	0.074
4.0	93.0	0.7	0.12
9.3	96.0	0.0	0.83

* Stoichiometric mole ratio based on inlet sulfur dioxide level of 940 ppm.

TABLE 6. TYPICAL SOLUTION ANALYSIS AT SODIUM LEVELS OF 0.17 PCT, 0.66 PCT, 4.0 PCT, AND 9.3 PCT

Species	Percent Sodium:	0.17	0.66	4.0	9.3
Ca (ppm)		708	631	643	762
Mg (pct)		1.30	1.33	1.3	1.2
SO_4 (pct)		7.06	7.66	15.0	26.0

The solids settling properties were observed to degrade as the ionic strength of the scrubber solution increased. This phenomenon has been observed previously in EPA laboratory testing on dilute double alkali systems, and by Arthur D. Little, Inc. (8) in laboratory and pilot plant work on dilute and concentrated double alkali systems. Factors reported to influence the solids settling properties are reactor configuration, concentration of soluble magnesium and iron, and the concentration of soluble sulfate. In this investigation, the concentration of magnesium and iron were relatively constant. However, the level of soluble sulfate varied along with sodium level, due to the addition of sodium as sodium sulfate. The solids settling characteristics degraded correspondingly.

It can be seen from Table 5 that the rate of scaling decreased as the sodium concentration increased. The absence of scale formations at the 9.3 pct sodium level is thought to be a function of sodium and not due to the higher (0.83 pct) level of suspended solids, since past work at similar levels of suspended solids (low sodium) resulted in scaling rates of 1 to 2 gm/hr. The stack flue gas was also tested to determine if sulfate was being lost in the mist. If sulfate was lost in the mist at a rate equal to or

greater than that being absorbed into the scrubber solution (assuming constant liquid volume in the system), scaling would not be expected to occur. Extensive testing indicated this did not occur, and thus, the absence of scaling is concluded to be a result of high sodium concentration.

It can also be seen from Table 5, that an increase in the level of total dissolved solids did not have a significant effect on sulfur dioxide removal, which contradicts previous results. The current result showing no effect on removal was observed after the modification of the scrubber by installation of "rain and drain" trays, which greatly increased gas-liquid contact in the scrubber. The conclusion to be drawn is that a high ionic strength in terms of sodium and magnesium sulfates increases removal for a scrubber configuration providing minimum contact-residence time (the flooded disk venturi alone), but that it does not increase removal for a scrubber providing a maximum of contact-residence time (the venturi plus trays). The results further indicate that the scrubber solution having low ionic strength had a sufficient equilibrium capacity to absorb essentially all of the entering sulfur dioxide (at 840 ppm and L/G = 45), but that this capacity was not fully utilized without the increased residence-contact time. On the other hand, the scrubber liquor having high ionic strength was indicated to be capable of more rapid absorption of sulfur dioxide so that essentially all entering sulfur dioxide could be removed with a short residence-contact time. Thus, the final conclusion is that sulfur dioxide removal in ash alkali scrubbing can be materially improved by either an increase in ionic strength or an increase in residence-contact time, but that a substantial increase in either can mask the effect of the other.

Oxidation of absorbed sulfur dioxide to sulfate was generally high for all test conditions (98 to 99 pct sulfate). The percentage of sulfite was, however, higher in the test run at 9.34 pct sodium (2 pct sulfite) than in any other test.

SMEC TEST PROGRAM

The Square Butte Electric Cooperative (SMEC) is currently constructing a 450 MW cyclone-fired generating unit requiring particulate and sulfur dioxide abatement controls. The 450 MW unit is referred to as Center unit No. 2 and is being constructed adjacent to the 230 MW Center unit No. 1 at the Milton R. Young Station. Particulate control will be provided by electrostatic precipitators (ESPs) and sulfur dioxide control by wet scrubbers.

A testing program using a 5000-acfm (saturated) pilot plant was conducted under a cooperative agreement between SMEC, Minnesota Power and Light Company (MP&L), Combustion Equipment Associates (CEA), and GFERC. Participation by GFERC in the cooperative test program during Fiscal Year 1976 was funded by EPA. The pilot scrubber was designed and constructed by Combustion Equipment Associates. The objectives of the cooperative program are:

1. To determine whether sufficient alkali can be solubilized from cyclone-fired fly ash to reduce sulfur dioxide in flue gas below the level of State and Federal emission standards.

2. To determine the amount of additional alkali from lime which may be required to supplement fly ash alkali to meet State and Federal emission standards.

3. To determine the severity of calcium sulfite and calcium sulfate scale formation under normal operating conditions of the flue gas desulfurization pilot scrubber, and to investigate chemical methods of minimizing the scale formation.

4. To establish that the pilot scrubber can be operated on a closed-loop basis, and to determine the chemistry of the closed-loop system.

5. To determine what effect fly ash-derived soluble salts in the scrubber solution will have on the sulfur dioxide removal efficiency.

6. To determine and evaluate waste disposal of sulfate/sulfite sludge and fly ash-derived soluble salts in sludge.

7. To conduct corrosion tests to determine the effects of scrubber liquor on materials of construction to be used for full-scale flue gas desulfurization processes.

8. To determine the mass balance of all input and output materials, including selected trace elements and leachate from sludge.

9. To evaluate the capital and operating costs of fly ash alkali flue gas desulfurization for 100 MW, 500 MW, and 1000 MW steam generator plants based on the technical and operating data obtained from the pilot scrubber.

10. To confirm design criteria and operating parameters for a full-scale 450 MW scrubber employing the fly ash alkali process.

At the conclusion of the EPA-sponsored research at GFERC, not all objectives had been met, and the research was continued under funding from the Energy Research and Development Administration (ERDA).

Additional phases of testing may be concerned with dilute sulfuric acid scrubbing with fly ash neutralization, and with sodium-magnesium and calcium double-alkali-type scrubbing with fly ash neutralization.

The 5000-acfm (saturated) pilot plant scrubber (about 1.4 MW equivalent) employs spray nozzles to minimize the gas side pressure drop across the absorption tower. The pilot plant (see Figure 4) has, essentially, two liquid loops: the primary sulfur dioxide scrubber loop, and the mist eliminator and wash tray loop.

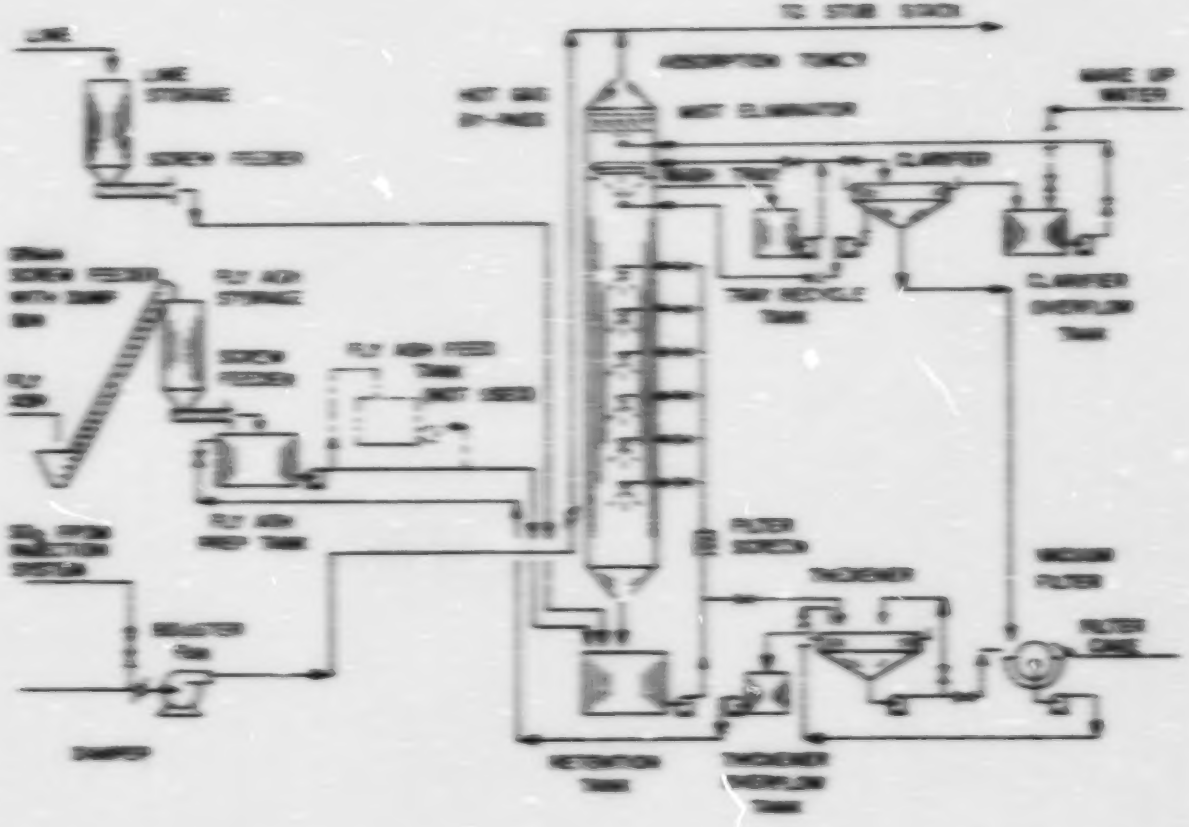

Figure 4. 5MW-scale pilot plant scrubber, Square Butte Electric Cooperative.

The wash tray loop, designed to operate on clear liquor at an approximate pH of 2 to 4, consists of a wash tray above the absorber tower, a tray recycle tank, clarifier and clarifier overflow tanks, and a demister. The wash tray, which is constructed of 316L stainless steel, was designed to remove entrained slurry which could otherwise foul the demister. Liquid from the wash tray drained to an 8 x 8-foot flakeglass-lined recycle tank which was then pumped back to the wash tray or to an 8 x 8-foot flakeglass-lined clarifier. Overflow from the clarifier was used to wash the bottom of the wash tray. Liquid from the clarifier not used for washing was drained by gravity to a 6 x 6-foot flakeglass-lined overflow tank. Makeup water from nearby Lake Nelson was added to the pilot scrubber at the clarifier overflow tank at an average rate of 1.4 gpm (about 1.6 acre-ft/MW/yr) and the combined liquid used to wash the polypropylene demister. Underflow from the clarifier was pumped to a drum-type vacuum filter.

The scrubber loop operates on a slurry of alkaline ash in recycled liquor at a pH of 2 to 7. It consists of a 45 foot high by 3 1/2- foot diameter flakeglass-lined absorber tower which contains six 316L stainless steel nozzles spraying scrubber liquid countercurrent to the gas flow. The scrubber liquid drained from the absorber tower to a 12 x 8-foot flakeglass-lined retention tank equipped with a 316L stainless steel agitator. The retention tank liquid was pumped back to the spray nozzles, to the fly ash prep tank to slurry fly ash, and to an 8 x 8-foot flakeglass-lined thickener used to control the level of suspended solids. Reducing the liquid flow from the retention tank to the thickener increased the level of suspended solids; increasing the flow rate lowered the level of suspended solids. Overflow from the thickener drained by gravity to a 5 x 5-foot flakeglass-lined overflow tank. Thickener underflow was pumped to the vacuum filter. The vacuum filter was operated only when the concentration of suspended solids in the thickener underflow had increased to approximately 55 to 60 pct; filtration was stopped when the solids were reduced to about 20 pct. Liquid from the thickener overflow tank was pumped to a 4 x 5-foot fly ash preparation tank with the excess liquid returning to the retention tank. Occasionally, retention tank liquor was used to slurry the fly ash. Fly ash was stored in a 3 x 5-foot hopper and fed to the preparation tank using a screw feeder at rates up to 8 lb/min. Hydrated lime from a 3 x 2-foot storage hopper was fed directly into the retention tank. The total amount of liquid in the entire pilot plant scrubber was about 12,000 gallons. All pumps were rubber lined. Liquid flows were measured by rotameter and magnetic flow meters; liquid and gas temperatures were measured by dial thermometers; pressure drops were measured by manometers and differential pressure cells.

The pilot plant scrubber was designed to have the necessary equipment and controls to operate over a wide range of variables. The solution pH can be varied from below pH 2 up to pH 9; the retention tank residence time can be varied from 4 minutes to 16 minutes; the liquid-to-gas ratio can be varied from 10 to 160; and a sulfur dioxide injection system can adjust the scrubber inlet sulfur dioxide to any desired concentration. A duct equipped with an orifice and damper was installed between the inlet and outlet of the absorption tower and used to bypass part of the hot inlet flue gas to mix with the cooler outlet flue gas leaving the absorption tower. The mixing

of flue gases in this manner was tested as a method for reheating to a temperature above the saturation point to eliminate the possibility of stack gas rain.

A mobile trailer supplied by the Grand Forks Energy Research Center provided the capability of continuously monitoring both the inlet and outlet flue gas for sulfur dioxide, nitrogen oxides, carbon dioxide and oxygen. In addition to the gas monitoring equipment, the trailer contained a chemistry laboratory to perform most analyses of coal and scrubber liquor on site.

The 5000-acfm (saturated) pilot plant scrubber, designed and constructed by CEA-ADL, had the primary purpose of confirming design criteria and operating parameters for the full-scale scrubber. Information for design of the 450 MW commercial unit was generated in a two-month test program conducted by CEA-ADL in cooperation with SOEC, MP&L and GFERC. An additional two-month reliability test was also conducted.

Sulfur dioxide in the flue gas must be reduced to approximately 535 ppm SO_2 (dry) to comply with the federal emission standard of 1.2 lb SO_2/MM Btu. The sulfur dioxide removal efficiency was investigated as a function of L/G, suspended solids, inlet sulfur dioxide concentration, and fly ash add rates. The ESP inlet fly ash particulate loading at the inlet to the ESP on Center unit No. 1 ranges from 0.71 to 1.53 gr/scf and averages 1.13 gr/scf. The two ash add rates investigated were equivalent to the combined average amount collected by the ESPs on Units 1 and 2, and the maximum amount collected on Units 1 and 2. A typical analysis of the Center fly ash is shown in Table 7.

TABLE 7. TYPICAL ANALYSIS OF LIGNITE FLY ASH PRODUCED BY CYCLONE-FIRED CENTER UNIT NO. 1 AT THE MILTON R. YOUNG STATION

	Percent of ash, as received
Loss on ignition at 800° C	2.2
Silica, SiO_2	29.6
Aluminum oxide, Al_2O_3	12.7
Ferric oxide, Fe_2O_3	10.6
Titanium oxide, TiO_2	0.5
Phosphorous pentoxide, P_2O_5	0.3
Calcium oxide, CaO	25.7
Magnesium oxide, MgO	4.5
Sodium oxide, Na_2O	2.2
Potassium oxide, K_2O	2.0
Sulfur trioxide, SO_3	6.4
TOTAL	96.9

Figure 5 illustrates the sulfur dioxide removal efficiency at the above fly ash add rates at L/G ratios of 60 and 80. The solid line corresponds to the average fly ash production collected by both units, hereafter referred to as the average ash add rate. The dashed line corresponds to the maximum fly ash production by both units, hereafter referred to as the maximum ash add rate. A sulfur dioxide level of about 1100 ppm (dry) would be equivalent to about a 0.75 pct sulfur coal (HHV6604 Btu/lb, as received). A level of 1850 ppm (dry) is equivalent to about 1.3 pct sulfur in coal. The outlet sulfur dioxide represents the removal for the total scrubber system, which includes the flue gas by-passed and used for reheat. The total flue gas into the system was 7400 acfm, of which 1100 acfm was by-passed. The inlet gas temperature was about 325° F. The temperature of the saturated gas (5000 acfm) out of the absorber tower was about 135° F. After mixing the by-pass gas, the temperature of the gas to the stack was about 155° F. The flue gas reheat was tested as an alternative to coil reheaters. No stack gas mist was observed to occur. The averaged results from the design and operating criteria test program are summarized in Table 8. Results of each test series are illustrated in Figure 5 and are tabulated in Appendix A.

At a L/G of 60 and an averaged inlet level of about 1053 ppm SO_2 (dry) using fly ash at the average add rate, the sulfur dioxide removal efficiency for the total scrubber system was about 61.3 pct (absorber tower removal efficiency was about 72.1 pct). The fly ash alkali utilization, based on inlet sulfur dioxide and 25 pct CaO in the fly ash, was about 100 pct. At the maximum ash add rate and an averaged inlet level of 987 ppm SO_2 (dry), the sulfur dioxide removal was about 69.3 pct (absorber tower removal efficiency was about 81.5 pct). The fly ash CaO utilization was 72 pct. Supplemental hydrated lime was not added and the pH of the recycle slurry was about 3.9 at the average ash add rate and 5.3 at the maximum ash add rate.

At a L/G of 60 and an averaged inlet level of about 1074 ppm SO_2 (dry), using the average fly ash add rate with lime supplement, the total scrubber system removal efficiency was about 69.2 pct (absorber tower removal efficiency was about 81.4 pct). Supplemental hydrated lime was added to maintain the pH at 6.6 to 6.8, and represented about 63.1 pct of the total CaO; the total alkali (fly ash alkali and hydrated lime supplement) was equivalent to about 100 pct of the inlet sulfur dioxide. At the maximum ash add rate with hydrated lime supplement, the sulfur dioxide removal remained at about 71 pct (absorber tower removal efficiency was about 83.5 pct). Supplemental hydrated lime was added to maintain the pH at 6.6 to 6.8 and represents 48.1 pct of the total CaO; total CaO (fly ash alkali and hydrated lime supplement) was equivalent to about 120 pct of the inlet sulfur dioxide. In a separate test using only hydrated lime chemically equivalent to that of the total alkali, the removal efficiency increased to about 79 pct.

At a L/G of 80 and an averaged inlet level of about 1077 ppm SO_2 (dry) using fly ash at the average add rate, the sulfur dioxide removal efficiency for the total scrubber system was about 71 pct (absorber tower removal efficiency was 83.5 pct). The fly ash CaO utilization was about 110 pct. The pH of the recycle slurry was about 3.8. No supplemental hydrated lime was used. At the maximum ash add rate and at an averaged inlet of 1100 ppm SO_2 (dry),

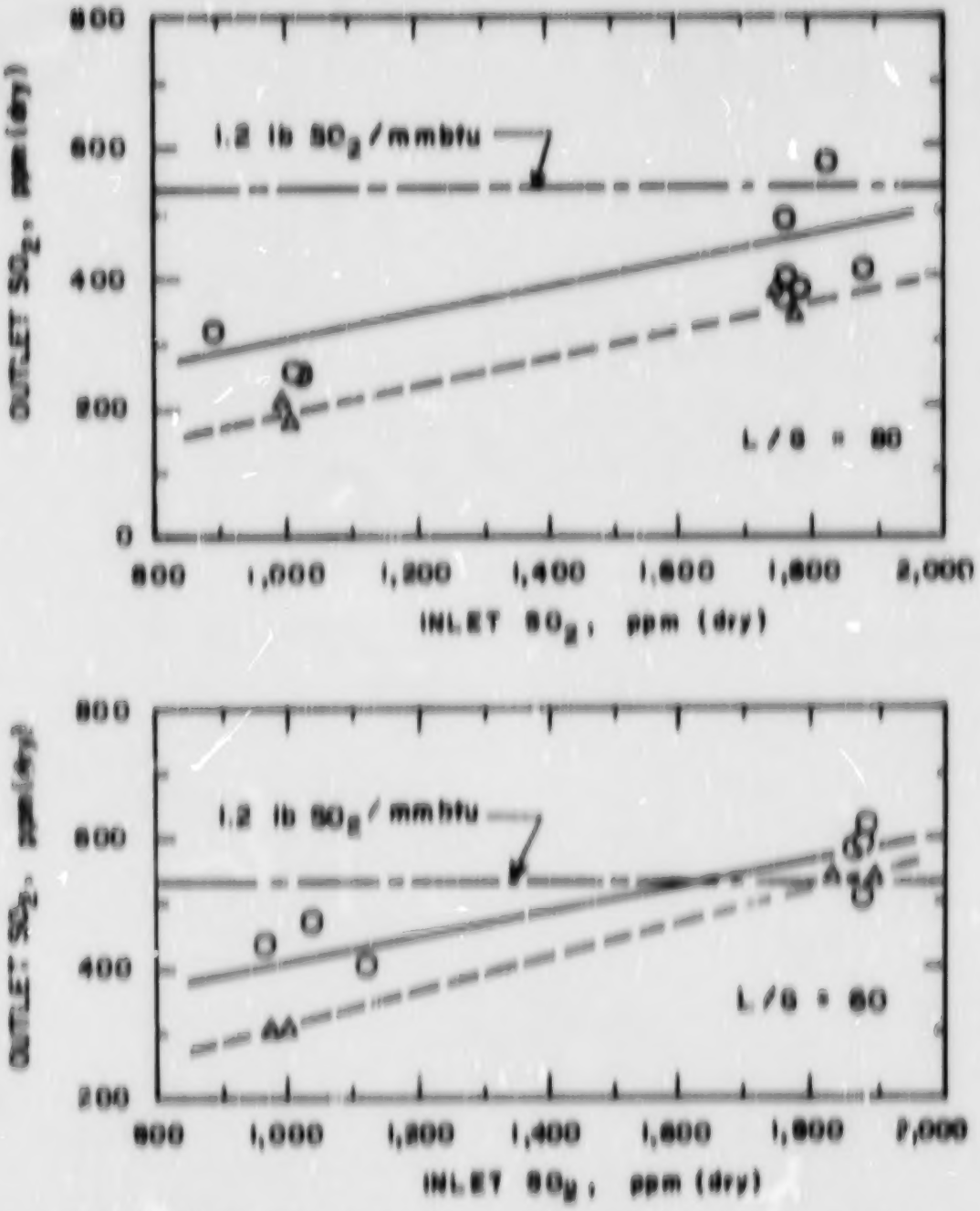

Figure 5. Sulfur dioxide removals in RDREC pilot plant tests using fly ash alkali. Solid line represents average fly ash (1.13 gr/scf) collected by ESPs; dashed line represents maximum fly ash (1.53 gr/scf) collected by ESPs.

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using hydrated supplemental lime, the total scrubber system sulfur dioxide removal was about 51.8 pct (absorber tower removal efficiency was about 96.2 pct). The supplemental hydrated lime was added to maintain the pH at 6.0 to 6.5, and represented 30.6 pct of the total CaO; the total CaO (fly ash alkali and supplemental hydrated lime) was equivalent to about 149 pct of the inlet sulfur dioxide.

At a L/G of 80 and an averaged inlet level of about 1900 ppm SO_2 (dry), the removal efficiency for the total scrubber system was about 76.9 pct at the average ash add rate (absorber tower removal efficiency was about 96.2 pct). Supplemental hydrated lime was added to maintain the pH at 6.5 to 6.8, and represents about 64.5 pct of the total CaO; the total CaO (fly ash alkali and supplemental hydrated lime) was equivalent to 107 pct of the inlet sulfur dioxide. At the maximum add rate and an averaged inlet level of 1870 ppm SO_2 (dry), the removal efficiency for the total scrubber system was about 80.4 pct (absorber tower removal efficiency was about 94.5 pct). Supplemental hydrated lime was added to maintain the pH at 6.5 to 6.7, and represented 53.6 pct of the total CaO; the total CaO was equivalent to about 126 pct of the inlet sulfur dioxide. A test using only hydrated lime chemically equivalent to about 134 pct of the inlet sulfur dioxide resulted in a scrubber system removal of about 86 pct (absorber tower removal efficiency about 99 pct).

The pilot test results demonstrate that the scrubber design to be used on the full-scale unit is capable of meeting and exceeding removals required to comply with the 1.2 SO_2 lb/MM Btu Federal emission standard, and further, that required removals under normal conditions of coal sulfur content can be achieved using fly ash alone without lime. The higher sulfur dioxide removals demonstrated in pilot plant tests were obtained by adding hydrated lime at rates higher than intended for the 450 MW scrubber unit, and these high rates may not be reproduced in practice on the commercial scale scrubbers.

At the conclusion of the eight-week test program, the scrubber system was inspected for scale, and it was reported to have a light scale, with most deposits at wet-dry interfaces. However, to further investigate scaling and reliability problems associated with fly ash alkali scrubbing, an additional eight weeks of operation using the projected full-scale scrubber operating parameters was initiated.

SDEC Reliability Test Program

The reliability test program was divided into two 4-week studies. The first 4-week study investigated the worst case coal sulfur content of 1.3 pct (about 1550 ppm-dry SO_2); the second 4-week study investigated the average coal sulfur content of 0.75 pct (about 1000 ppm-dry SO_2). The pilot plant operating parameters were: L/G of 80, pH of 6.5 to 6.8 at 1.3 pct coal sulfur content, pH of about 4 at 0.75 coal sulfur content, 15 pct of the inlet flue gas was by-passed and used for reheat. The averaged results are shown in Table 9 and Figure 6.

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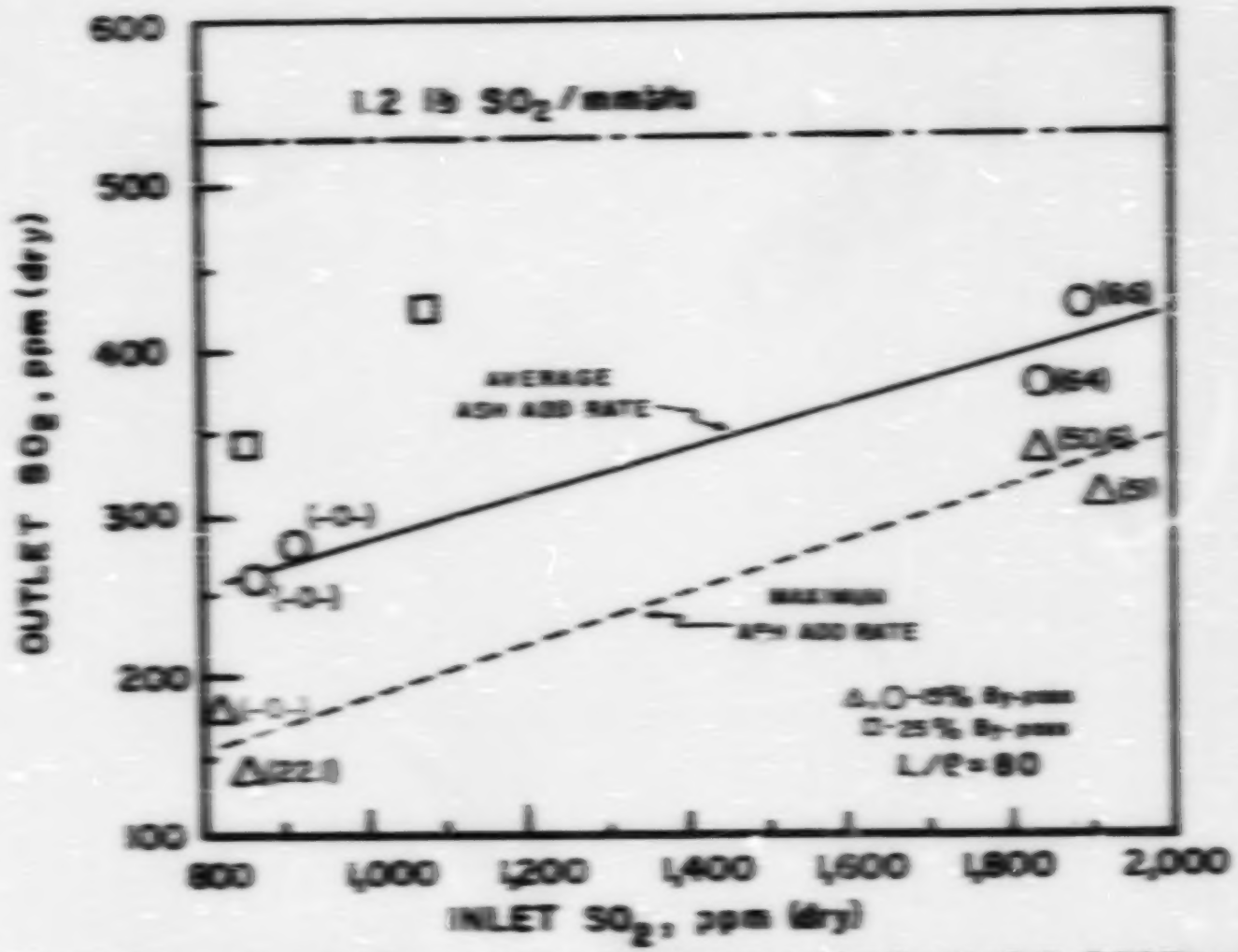

Figure 6. SO_2 removals in EERC reliability pilot plant tests using fly ash alkali. Solid line represents fly ash (1.13 gr/scf) collected by ESPs. Dashed line represents maximum fly ash (1.5) gr/scf) collected by ESPs. Numbers in parentheses denote stoichiometric % of supplemental hydrated lime. Squares denote results obtained using 25% flue gas by-pass.

Figure 6 illustrates the sulfur dioxide removal efficiencies obtained during the reliability test program. The dashed line corresponds to the maximum fly ash production by the electrostatic precipitators on both units, and is referred to as the maximum ash add rate. The solid line corresponds to the average fly ash production by the electrostatic precipitators on both units, and is referred to as the average ash add rate. The outlet sulfur dioxide represents the removal for the total scrubber system, which includes the flue gas by-passed and used for reheat.

At the worst case condition of 1.3 pct coal sulfur (about 1850 ppm-dry SO_2), both ash add rates were investigated. In two 1-week tests at the maximum ash add rate, the sulfur dioxide removal efficiency for the total scrubber system was 79.9 pct and 84.0 pct (absorber tower was 94.0 and 96.8 pct, respectively). Supplemental hydrated lime was used to maintain the pH at 6.5 to 6.8, and represents about 50 pct of the total alkali (actual percentages are illustrated by parenthesis in Figure 6). The fly ash CaO contributed about 50 pct of the total alkali and the utilization varied from about 51 pct to about 61 pct. At the average fly ash add rate, the sulfur dioxide removal efficiency for the total scrubber system was about 77.6 pct (absorber tower was about 91.1 pct). Supplemental hydrated lime was added to maintain the pH at 6.5 to 6.8, and represents about 66 pct of the total alkali. The fly ash alkali contributed about 34 pct of the total alkali and the utilization varied from 39.8 pct to 59.8 pct.

At the average coal sulfur content of 0.75 pct (about 1000 ppm-dry SO_2), both ash add rates were investigated. At the maximum ash add rate, without supplemental lime, the sulfur dioxide removal for the scrubber system was 77.0 pct (absorber tower was 90.6 pct); the corresponding ash CaO utilization was 78.0 pct. Using 22.1 pct supplemental hydrated lime, the sulfur dioxide removal was 80.2 pct (absorber tower was 94.4 pct); the corresponding fly ash CaO utilization was 58.5 pct. In two 1-week tests at the average ash add rate, without supplemental hydrated lime, the average sulfur dioxide removal efficiency for the scrubber system was 70.4 pct and 69.9 pct (absorber tower was 82.8 and 82.2 pct); the corresponding fly ash CaO utilization was 100 pct and 113 pct, respectively.

Two additional tests not related to the full-scale operating parameters were conducted during the reliability test program. The first test (Table 8, test 10) was conducted using 25 pct flue gas bypass for reheat at the average coal sulfur content of 0.75 pct, using the average fly ash add rate. The results are denoted by squares in Figure 6, and it can be seen that the sulfur dioxide emissions are below the Federal standard.

The second test (Table 8, test 11) was conducted using a L/G of 60 at the average coal sulfur content of 0.75 pct (about 1000 ppm-dry), and the average fly ash add rate. The results indicate, as shown previously in Figure 5, that the Federal standard can be met. The implication of this result is that the full-scale scrubber could operate at a lower L/G during periods of average coal sulfur content. This could be accomplished by stopping flow to a bank(s) of spray nozzles, thus reducing pump requirements. As a consequence, power consumption would be reduced.

Typical analyses of the absorber tower feed liquor and of the wash tray feed liquor are shown in Table 10. These analyses are the averaged concentrations of test series 6 through 12, and are representative of a typical analysis.

TABLE 10. TYPICAL ANALYSES OF SCRUBBER SOLUTIONS FROM THE SBEC RELIABILITY TEST PROGRAM

	Absorber Tower Feed	Wash Tray Feed
Calcium*	490	460
Magnesium	6555	1119
Sodium	2390	1093
Potassium	1267	339
Chloride	110	30
Sulfite	<0.6	<0.6
Sulfate	37420	10136
Total solids, pct	14.2	2.1
Suspended solids, pct	0.7	1.3
pH	4.82	3.0

* Concentration units are ppm unless otherwise noted.

The state of oxidation was high, usually greater than 98 pct oxidation of sulfite to sulfate; no apparent off-gassing of sulfur dioxide occurred at any pH value.

The pilot scrubber was inspected for corrosion, erosion, and scale deposits on a weekly basis. Detailed visual inspections were performed at the absorber tower flue gas inlet and interior walls, wash tray, mist eliminator, stainless steel test pieces inserted into the absorber tower. The principal operational difficulties are summarized in the following sections.

Absorber Tower--The absorber tower wall is lined with flakeglass-reinforced polyester to protect the mild steel from corrosion due to the acidic scrubbing liquors. After about four months of operation, the lining was eroded in the area where slurry from the spray nozzle impacts the wall. The lining opposite the flue gas inlet was also eroded, which is believed to be a problem characteristic to pilot plant scrubbers due to the relatively small diameter of the absorber tower. In some unwashed areas of the absorber tower, scale deposits accumulated. The accumulations occur primarily during periods of high pH (about 6.5) operation. When test conditions resulted in a low pH, the scale deposits appeared to dissolve and eventually disappeared.

Wash Tray--Some solid deposits were observed on both the top and the bottom of the wash tray when the solution pH was maintained at about 6.5. At the conclusion of the test period requiring the high pH, the wash tray required manual cleaning.

During the test period in which the solution pH was low (below 4.8), no accumulation of solids was detected. Control of the deposits appeared possible by operating at a constant low pH range (below 4.8) that still removed sufficient sulfur dioxide to meet the Federal emission standard.

Spray Nozzles--The spray nozzles used in the testing program were constructed of 316L stainless steel. The nozzles had an average life of about two months due to erosion by a scrubber solution containing about 12 pct suspended solids. In comparison, a set of carbon steel spray nozzles lasted only ten days.

Vacuum Filter--Above pH 4, the sludge had excellent filtering characteristics. In general, the sludge had a solids content of over 50 pct. However, as the scrubber solution pH dropped below 4, the sludge became difficult to filter and the pores of the 200-mesh filter cloth plugged. The solids content of the sludge remained high, generally greater than 50 pct; however, the physical appearance of the sludge indicated that the average particle size had decreased. The decreased particle size would be consistent with a greater proportion of the fly ash dissolving and reacting at low pH levels. The filter cloth pore pluggage was resolved by the installation of a high pressure air manifold following the wash water header.

Wet-Dry Zones--An accumulation of solids occured at the flue gas inlet to the absorber tower. The build-up of solids was due to the dehydration of slurry which contained about 12 pct suspended solids. The problem was resolved by the installation of high pressure sprays inside the flue gas duct. At 8-hour intervals, the sprays were turned on for three minutes to dislodge the dehydration deposits.

Two other operational problems were occasional plugging of pipes and erosion of plastic valves and plastic pipes at contractions and bends. The erosion was due to the high level of suspended solids circulating in the system.

COYOTE STATION TEST PROGRAM

The Otter Tail Power Company, in association with Minnkota Power Cooperative, Minnesota Power and Light Company, Montana-Dakota Utilities, and Northwestern Public Service Company, are planning to construct a nominal 400 MW cyclone-fired boiler (called the Coyote Station) which will burn Beulah, North Dakota, lignite. The Coyote Station is required to meet the NSPS of 1.2 lb SO_2/MM Btu, and a short test program investigating scrubbing with four lignite fly ashes was conducted on the SREC 5000-acfm pilot plant. Detailed planning of the test program was performed by Bechtel Power Corporation, consulting engineers to Otter Tail Power, and was approved by the pilot scrubber steering committee in accordance with the EPRDA cooperative agreement.

The purpose of the test program was to compare the alkali utilization of four fly ashes and the corresponding sulfur dioxide removal at a specified pH and L/G in an attempt to predict the behavior of the proposed Coyote fly ash. Two fly ashes tested were a high sodium and low sodium fly ash from the

Beulah, North Dakota mine, and were collected from an electrostatic precipitator at Otter Tail Power's pc-fired Hoot Lake Station. The proposed Coyote Station will burn Beulah lignite. The third fly ash was collected from an electrostatic precipitator at Otter Tail Power's cyclone-fired Big Stone Station, which burns lignite from the Gascoyne, North Dakota, mine. The Big Stone fly ash differs chemically from the Hoot Lake ash, but it is fired in a Coyote-type cyclone boiler. The fourth fly ash was collected from electrostatic precipitators at the cyclone-fired Basin Electric Station at Stanton, North Dakota, which burns a lignite from the Glenharold, North Dakota, mine. The Basin fly ash has a chemical composition similar to the low sodium Beulah ash.

The Coyote Station program was conducted at three sets of test conditions. In the first set of conditions, sufficient fly ash was added to maintain the solution pH at 4.5 at a constant L/G. This allowed comparisons to be made of the alkali utilizations of the four fly ashes, and also of sulfur dioxide removal. In the second set of conditions, the fly ash feed was reduced to match the expected particulate loading of the proposed Coyote Station, and supplemental hydrated lime was added to maintain the pH at 4.5. At the third test condition, the fly ash add rate was maintained at the expected particulate loading, and sufficient hydrated lime was added to maintain the pH at 5.0.

The first fly ash tested contained low sodium and was collected from the electrostatic precipitators of the pc-fired Hoot Lake Station, which burns Beulah lignite. This coal will be burned in the proposed Coyote station. The chemical composition of the fly ash would be similar to the Coyote fly ash; however, the method of firing would be different (pc versus cyclone) and the results cannot be correlated directly to the proposed Coyote Station. A typical fly ash analyses is shown in Table 11.

TABLE 11. TYPICAL ANALYSIS OF BEULAH, NORTH DAKOTA LOW SODIUM FLY ASH

	Percent of ash, as received
Loss on ignition at 800° C	1.1
Silica, SiO_2	28.0
Aluminum oxide, Al_2O_3	14.2
Ferric oxide, Fe_2O_3	11.0
Titanium oxide, TiO_2	0.5
Phosphorous pentoxide, P_2O_5	0.6
Calcium oxide, CaO	27.0
Magnesium oxide, MgO	7.4
Sodium oxide, Na_2O	4.0
TOTAL	99.9

The results of the tests using the low sodium Beulah fly ash are shown in Table 12. Flue gas by-pass was not used.

TABLE 12. SUMMARY OF RESULTS USING LOW SODIUM FLY ASH

	Test Number		
	1-A	1-B	1-C
L/G[a]	77	80	79
Inlet SO_2, ppm	844	825	787
Outlet SO_2, ppm	214	99	110
SO_2 removal, pct	75	88	86
Fly ash add rate (ton/hr)	14.7	13.9	14.1
Hydrated lime add rate (ton/hr)	-0-	1.6	1.9
Lime, pct of total CaO	-0-	24.6	31.6
Ash utilization, pct	96.9	77.0	61.6
pH	4.8	4.6	5.0
CaO-total/SO_2+[#]	0.75	1.1	1.2

[a] L/G based on gallons of recycled slurry per 1000 acf saturated flue gas.
+ Stoichiometric ratio based on absorber tower inlet SO_2.
# Fly ash CaO content was averaged during test period.

A typical solution analysis of the absorber tower feed and the wash tray feed are shown in Table 13.

TABLE 13. TYPICAL SOLUTION ANALYSIS USING LOW SODIUM FLY ASH

	Absorber Tower Feed	Wash Tray Feed
Calcium[a]	431	466
Magnesium	3332	1540
Sodium	2360	1437
Potassium	171	111
Chloride	50	48
Sulfite	<0.8	<0.8
Sulfate	10731	12275
Total solids, pct	11.6	--
Suspended solids, pct	6.9	--

[a] Concentration units are ppm unless otherwise noted.

The second fly ash tested was a high sodium Beulah fly ash obtained from the electrostatic precipitators of the pc-fired Hoot Lake Station. The high sodium Beulah coal will also be burned in the proposed Coyote Station. A typical fly ash analysis is shown in Table 14.

TABLE 14. TYPICAL ANALYSIS OF BEULAH, NORTH DAKOTA, HIGH SODIUM FLY ASH

	Percent of ash, as received
Loss on ignition at 800° C	0.1
Silica, SiO_2	34.4
Aluminum oxide, Al_2O_3	12.1
Ferric oxide, Fe_2O_3	10.1
Titanium oxide, TiO_2	0.9
Phosphorous pentoxide, P_2O_5	0.5
Calcium oxide, CaO	22.7
Magnesium oxide, MgO	5.7
Sodium oxide, Na_2O	10.7
Potassium oxide, K_2O	0.8
Sulfur trioxide, SO_3	11.5
TOTAL	99.5

The results of the tests using the high sodium Beulah fly ash are shown in Table 15. Flue gas by-pass was not used.

TABLE 15. SUMMARY OF RESULTS USING HIGH SODIUM FLY ASH

	Test Number		
	Z-A	Z-B	Z-C
L/G*	80	80	80
Inlet SO_2 ppm (dry)	770	760	760
Outlet SO_2 ppm (dry)	65	77	50
SO_2 removal, pct	91.6	89.9	93.4
Fly ash add rate, ton/hr	22.6	14.1	13.1
Hydrated lime add rate, ton/hr	-0-	2.0	3.1
Lime, pct of total CaO	-0-	32.3	44.9
Ash utilization, pct	74.6	61.6	45.0
pH	4.4	4.5	5.1
CaO/SO_2†#	1.23	1.2	1.36

* L/G based on gallons of recycled slurry per 1000 acf saturated flue gas.
† Stoichiometric ratio based on absorber tower inlet SO_2.
\# Fly ash CaO was averaged during test period.

A typical solution analysis of the absorber tower feed and the wash tray feed are shown in Table 16.

TABLE 16. TYPICAL SOLUTION ANALYSIS USING HIGH SODIUM FLY ASH

	Absorber Tower Feed	Wash Tray Feed
Calcium*	457	430
Magnesium	7312	1027
Sodium	9060	1886
Potassium	457	107
Chloride	140	55
Sulfite	<0.0	<0.8
Sulfate	47333	13493
Total solid , pct	15.6	--
Suspended solids, pct	10.2	--

* Concentration units are ppm unless otherwise noted.

The third test used a fly ash collected from the electrostatic precipitators from the cyclone-fired Big Stone Station, which burns lignite from the Gascoyne mine. The chemical composition of the fly ash is slightly different from the low sodium Beulah ash, but is burned in a Coyote-type cyclone boiler. A typical fly ash analysis is shown in Table 17.

TABLE 17. TYPICAL ANALYSIS OF BIG STONE FLY ASH

	Percent of ash, as received
Loss on ignition at 800° C	0.8
Silica, SiO_2	49.3
Aluminum oxide, Al_2O_3	12.9
Ferric oxide, Fe_2O_3	3.1
Titanium oxide, TiO_2	1.2
Phosphorous pentoxide, P_2O_5	0.4
Calcium oxide, CaO	17.9
Magnesium oxide, MgO	6.1
Sodium oxide, Na_2O	3.7
Potassium oxide, K_2O	0.6
Sulfur trioxide, SO_3	3.0
TOTAL	99.0

The results of the tests using Big Stone fly ash are shown in Table 18. Flue gas by-pass was not used.

TABLE 18. SUMMARY OF RESULTS USING BIG STONE FLY ASH

	Test Number			
	3-A	3-B	3-C	3-D
L/G*	80	80	87	80
Inlet SO_2 ppm, (dry)	780	763	839	740
Outlet SO_2 ppm, (dry)	103	120	77	65
$S/_2$ removal, pct	86.9	84.0	91.0	91.0
Fly ash add rate, ton/hr	24.3	33.4	13.9	13.9
Hydrated lime add rate, ton/hr	-0-	-0-	3.9	3.6
Lime, pct of total CaO	-0-	-0-	53.0	52.0
Ash utilization, pct	87.5	60.1	48.9	39.7
pH	4.15	4.4	4.5	5.0
CaO/SO_2†#	1.0	1.4	1.2	1.3

* L/G based on gallons of recycled slurry per 1000 acf saturated flue gas.
† Stoichiometric mole ratio based on absorber tower inlet SO_2.
\# Fly ash CaO was averaged during test period.

One additional test was conducted using the Big Stone fly ash in which sufficient fly ash was added to maintain the pH at 4.15, as shown in column 3-a. These results may be compared to those obtained at a pH of 4.4, shown in column 3-b. Lowering the pH from 4.4 to 4.15 increased the fly ash alkali utilization from 60.1 pct to 87.5 pct. This increase in alkali utilization is consistent with the increased availability of ash calcium oxide with decreasing pH values, as shown in Figure 2. In a lime scrubber operating at much lower liquid-to-gas ratios, a lowered pH value would be expected to result in a lowered sulfur dioxide removal efficiency due to a decrease in the absorption of sulfur dioxide from flue gas to scrubber liquor. However, as the results in tests 3-a and 3-b illustrate, the removal did not decrease but remained approximately the same. These results can be attributed to the increased solubility of the fly ash alkali as a function of decreasing pH values and having a sufficiently high liquid-to-gas ratio to offset the decrease in sulfur dioxide absorption from flue gas to scrubber liquor. The decrease in fly ash CaO utilization with increasing pH values can be seen in columns 3-c and 3-d, which were conducted at a pH of 4.5 and 5.0, and the CaO utilizations are 48.9 pct and 39.7 pct, respectively.

A typical solution analysis of the absorber tower feed and the wash tray feed are shown in Table 19.

The fourth test used a fly ash collected from the electrostatic precipitators from Basin Electric Cooperative, which burn Stenharold coal. The coal ash has a chemical composition similar to the low sodium Beulah coal ash and is fired in a cyclone-fired boiler. A typical fly ash analysis is shown in Table 20.

TABLE 19. TYPICAL SOLUTION ANALYSIS USING BIG STONE FLY ASH

	Absorber Tower Feed	Wash Tray Feed
Calcium*	463	445
Magnesium	8540	1292
Sodium	2093	1271
Potassium	176	88
Chloride	90	47
Sulfite	<0.8	<0.8
Sulfate	28665	12536
Total solids, pct	16.1	--
Suspended solids, pct	10.3	--

* Concentration units are ppm unless otherwise noted.

TABLE 20. TYPICAL ANALYSIS OF BASIN FLY ASH

	Percent of ash, as received
Loss on ignition at 800° C	2.7
Silica, SiO_2	39.1
Aluminum oxide, Al_2O_3	13.0
Ferric oxide, Fe_2O_3	6.7
Titanium oxide, TiO_2	0.6
Phosphorous pentoxide, P_2O_5	0.2
Calcium oxide, CaO	17.9
Magnesium oxide, MgO	4.2
Sodium oxide, Na_2O	8.0
Potassium oxide, K_2O	1.8
Sulfur trioxide, SO_3	5.7
TOTAL	99.9

The results of the tests using the Basin fly ash are shown in Table 21. Flue gas by-pass was not used.

A typical solution analysis of the absorber tower feed and the wash tray feed is shown in Table 22.

TABLE 21. SUMMARY OF RESULTS USING BASIN FLY ASH

	Test Number		
	4-a	4-b	4-c
L/G*	60	80	80
Inlet SO_2 ppm (dry)	798	794	789
Outlet SO_2 ppm (dry)	124	122	161
SO_2 removal, pct	84.5	84.7	79.7
Fly ash add rate, ton/hr	45.4	13.6	13.9
Hydrated lime add rate, ton/hr	-0-	3.1	3.6
Lime, pct of total CaO	-0-	49.3	52.0
Ash utilization, pct	46.7	61.3	40.9
pH	4.42	4.5	5.0
CaO/SO_2†#	1.0	1.1	1.2

* L/G based on gallons of recycled slurry per 1000 acf saturated flue gas.
† Stoichiometric mole ratio based on absorber tower inlet SO_2.
\# Fly ash CaO was averaged during the test period.

TABLE 22. TYPICAL SOLUTION ANALYSIS USING BASIN FLY ASH

	Absorber Tower Feed	Wash Tray Feed
Calcium*	413	419
Magnesium	1477	369
Sodium	3330	1116
Potassium	412	148
Chloride	68	45
Sulfite	55	<0.8
Sulfate	13960	6300

* Concentration units are ppm unless otherwise noted.

The variability of alkali availability at similar pH in the four lignite fly ashes tested is illustrated in the summary shown in Table 23.

TABLE 23. SUMMARY OF RESULTS AT pH 4.5

Test Number:	Beulah low sodium 1-a	Beulah high sodium 2-a	Big Stone 3-b	Basin 4-a
L/G	80	80	80	80
Fly ash feed, ton/hr	14.7	22.6	23.4	45.7
SO_2 removal, pct	75.0	91.6	84.0	84.5
pH	4.5	4.4	4.4	4.42
Utilization, pct	95.9	74.4	60.1	45.7
CaO in fly ash, pct	27.8	22.7	17.9	17.9
CaO/SO_2	0.75	1.03	1.40	1.90
Total alkali, pct	91.9	87.9	95.2	91.5

The above test data were generated by adding sufficient fly ash to maintain the recycle slurry pH at a constant value of about 4.5. By this method, calcium oxide availability may be compared. Only two of the above test results, 1-a and 2-a, can be directly compared since they are both derived from the same pc-fired boiler and ESP. The fly ashes differ chemically since fly ash 1-a is derived from a low sodium coal and fly ash 2-a is derived from a high sodium coal. The reactivity of the low sodium is greater than the high sodium fly ash at pH 4.5, as evidenced by the amount of ash required to maintain the pH at about 4.5. For the low sodium ash, 14.7 ton/hr was required as compared to 22.6 ton/hr for the high sodium. The fly ash used in tests 3-b and 4-a show less alkali availability, which could be due to the different chemical composition of the fly ashes, or to the difference in boilers from which the fly ash was derived.

Future work at GFERC will characterize the scrubbing characteristics of various fly ashes by the use of standardized experiments. The standardized tests will enable various fly ashes to be tested and compared, and would be related to performance in full-scale scrubbers.

MINNESOTA POWER AND LIGHT COMPANY TEST PROGRAM

The Minnesota Power and Light Company (MP&L) is presently constructing a 500 MW pc-fired boiler at the Clay Boswell Station. The boiler, called the Clay Boswell unit No. 4, will burn a Montana subbituminous coal and is required to meet the Federal emission standards of the Clean Air Act. Particulate and sulfur dioxide control will be provided by a two-stage scrubber. The fly ash will be removed in the first-stage venturi, and the alkali solubilized from the fly ash would then be utilized to remove sulfur dioxide in a spray tower. Supplemental fly ash will be available from bag filters on two existing boilers.

The test program was designed to investigate sulfur dioxide removal as a function of coal sulfur content and L/G, using Montana subbituminous fly ash collected from mechanical collectors on Clay Boswell Units 1 and 2. The test

program was originated by LEA, and was reviewed and approved by the pilot plant steering committee in accordance with the ERDA cooperative agreement.

The fly ash was collected from mechanical collectors at the Clay Boswell Station and, thus, is only representative of the larger particles entering a scrubber. The fly ash was transferred to the 5000-acfm pilot scrubber in cement trucks and stored in a silo until used. This publication reports on the first phase of testing; a contamination of the fly ash used in the second phase of testing made the results non-representative.

The first phase of the test program investigated two fly ash add rates at three levels of sulfur dioxide and three liquid-to-gas ratios (L/G). The three liquid-to-gas ratios were 60, 80, and 100 gal/1000 acf-saturated. The three sulfur dioxide levels were about 900 ppm-dry, 1100 ppm-dry, and 2100 ppm-dry. The fly ash feed rate corresponded to the proposed average (25 ton/hr) and maximum (50 ton/hr) particulate loading expected from the new 500 MW pc-fired boiler. The calcium oxide content in the subbituminous fly ash averaged about 16 pct. A typical analysis of the fly ash is shown in Table 24.

TABLE 24. TYPICAL ANALYSIS OF MPAL FLY ASH FROM COLSTRIP, MONTANA, SUBBITUMINOUS COAL

	Percent of ash, as received
Loss on ignition at 800° C	1.4
Silica, SiO_2	40.8
Aluminum oxide, Al_2O_3	16.8
Ferric oxide, Fe_2O_3	7.1
Titanium oxide, TiO_2	0.9
Phosphorous pentoxide, P_2O_5	0.3
Calcium oxide, CaO	16.1
Magnesium oxide, MgO	3.0
Sodium oxide, Na_2O	0.2
Potassium oxide, K_2O	0.5
Sulfur trioxide, SO_3	1.2
TOTAL	100.1

To meet the Federal emission limit of 1.2 lb SO_2/MM Btu, the outlet sulfur dioxide limitation is 450 ppm-dry. During MPSL's test program, flue gas bypass for reheat was not utilized. The total flue gas into the scrubber system was about 6300 acfm. The inlet gas temperature was about 330° F, and the temperature of the saturated flue gas out of the absorber tower was about 135° F. Annhydrous sulfur dioxide was injected into the inlet flue gas to duplicate various coal sulfur contents.

The first set of test conditions investigated a sulfur dioxide concentration of about 900 ppm-dry. A removal efficiency of about 90 pct is required to meet the Federal emission requirement. At a L/G of 100, an average particulate load of about 25 ton/hr, and an average sulfur dioxide inlet concentration of 870 ppm-dry, the observed removal efficiency was 81.4 pct. The corresponding fly ash CaO utilization was 104 pct, based on 17 pct calcium oxide. The recycle slurry pH was 3.5. The results are shown in test 101 in Table 25.

A typical solution analysis of the absorber tower feed and the wash tray feed is shown in Table 26.

TABLE 26. TYPICAL SOLUTION ANALYSIS OF MP&L ASH TEST

	Absorber Tower Feed	Wash Tray Feed
Calcium*	474	468
Magnesium†	2372	411
Sodium†	650	479
Potassium†	592	328
Chloride†	420	125
Sulfite†	<0.8	<0.8
Sulfate†	11287	5430
Total solids, pct	2.3	1.4
Suspended solids, pct	11.8	0.43

* Concentration units are ppm unless otherwise noted.
† Concentrations were gradually increasing during test.

The second set of test conditions investigated a sulfur dioxide concentration of about 1100 ppm-dry. This level of sulfur dioxide was investigated at four L/G values, 60, 80, 95, and 100, using a constant fly ash feed rate of about 25 tons/hr, which corresponds to the expected average particulate loading. A summary of results are shown in Table 25, tests 102, 201, 202, and 203. The required removal efficiency is about 80 pct. At each L/G tested, the sulfur dioxide removal was greater than that required to meet the Federal emission standard; essentially 100 pct of the fly ash calcium oxide was utilized.

The third set of test conditions investigated a sulfur dioxide concentration of about 2100 ppm-dry. The removal efficiency required for compliance with the Federal emission requirement is 79 pct. The parameters tested were L/G values of 80 and 95; the fly ash add rate was equivalent to the expected maximum particulate load of about 50 ton/hr. A summary of the results are shown in Table 25, tests 204 and 205. The sulfur dioxide removal efficiencies were considerably below the required 79 pct, and the observed values are 36.2 pct at a L/G of 80, and 57.6 pct at a L/G of 95. The corresponding fly ash calcium oxide utilization was 36.2 pct and 70.6 pct. The pH of the recycle slurry was 4.4 in the test at L/G of 80, and 5.0 in the

test at L/G of 95. The pH values are higher than in the previous tests, which is reflected in the lower calcium oxide alkali utilizations. At this level of sulfur dioxide, supplemental lime or limestone would be required to comply with the Federal emission standard.

The above results are useful in predicting probable sulfur dioxide removal efficiencies in a full-scale scrubber that is of similar design to the pilot scrubber. Therefore, to further test the reactivity of the subbituminous fly ash in a pilot scrubber similar to the full-scale scrubber to be constructed on Unit 4, MP&L will conduct additional pilot plant studies to generate design and operating data for a full-scale 500 MW scrubber.

The pilot scrubber will be a 1 MW equivalent, 3000-acfm-saturated two-stage scrubber. The first stage will consist of a venturi designed for particulate removal. The second stage will consist of a spray tower which will use recirculated fly ash slurry for sulfur dioxide absorption. The pilot scrubber will further investigate fly ash alkali scrubbing for this application in greater detail than the present study. The full-scale scrubber will have about 6 pct of the inlet flue gas diverted to two electrostatic precipitators, which will remove particulate matter. The flue gas will then be used to reheat the flue gas from the two-stage scrubber.

FIXED INVESTMENT AND OPERATING COST FOR 100 MW, 500 MW, and 1000 MW FLY ASH ALKALI PROCESS

This section describes the results of a capital and operating cost analyses for a 100 MW, 500 MW, and a 1000 MW fly ash alkali scrubber. The analyses were performed by Combustion Equipment Associates using a computer program developed by the Tennessee Valley Authority under EPA sponsorship, which was modified by CEA for the fly ash alkali process. The analyses are based on data generated during the SBEC test program and represent an accuracy of plus or minus 15 pct.

The 500 MW system was selected as the base case and used design and operating data generated during the SBEC test program; the test program previously generated design and operating data for the 450 MW system currently under construction at SBEC. A detailed equipment and source list is presented in Table 27. Some of the important design and cost assumptions are:

1. New Western coal-fired generating unit in Northwest location.
2. Coal HHV6400 Btu/lb (as received); heat rate of 10,000 Btu/KWH.
3. Worst case coal sulfur content of 1.3 pct (as received).
4. Sulfur dioxide removal in spray tower is 85 pct.
5. Stack gas reheat to 160° F using 15 pct flue gas bypass.
6. Flue gas particulate of 3.35 grain/scf (wet); 24 pct CaO in fly ash.

TABLE 27-a. [illegible]
PROCESS - MATERIAL HANDLING (LIME)

	Item	Units required	Description	Source	Unit cost, $	Total cost, $
1.	Lime storage silo	1	Capacity 15,000 ft^3 20 ft dia. x 45 ft steel side carbon steel dust collector	CEA		
2.	Weigh feet (Tike)	1	Capacity 1200 lbs/hr 12 in. belt width. Motor 1/4 HP D.C.	K-Tron		
			Costs, items 1 & 2		65,000	65,000
3.	Lime slaker	1	Capacity 150 GPM outlet flow. Holding capacity 800 gals, carbon steel, 2 agitator	CEA		
4.	Lime slaker transfer tank	1	Capacity 600 gals 5 ft dia. x 5 ft high	CEA		
5.	Agitator, slaker transfer tank	1	2 HP, carbon steel 1800 RPM	Philadelphia Gear		
6.	Lime slurry feed tank	1	Capacity 56,000 gals 23 ft dia. x 26 ft high	CEA		
7.	Agitator, slurry feed tank	1	15 HP, carbon steel 1800 RPM	Philadelphia Gear		
			Costs, items 3-7		71,000	71,000

(Continued)

TABLE 27-2. [illegible]

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

TABLE 27-6. [illegible]

	Item	Units required	Description	Source	Unit cost, $	Total cost, $
1.	Fly ash silo	1	Capacity [illegible] ft³ 22 ft dia. x 54 ft high with dust collector vibrating hopper	[illegible]		
2.	Weigh feed (Fly ash)	1	Capacity [illegible] lbs/hr 24 in. belt width, motor 1/2 HP D.C.	K-Tron		
			Costs, Items 1 & 2		[illegible]	[illegible]
3.	Fly ash slurry feed tank	1	Capacity [illegible] gals 23 ft x 25 ft high, carbon steel	[illegible]		
4.	Agitator, fly ash slurry feed tank (without motor)	1	15 HP, [illegible] RPM, carbon steel	Philadelphia Gear		
			Costs, Items 3 & 4		[illegible]	[illegible]
5.	Fly ash slurry feed pumps	2	Capacity [illegible] GPM, 50 ft TDH, 30 HP, carbon steel	Worthington Pumps, Inc.	3,750	7,500
			SUBTOTAL			[illegible]

TABLE 27-c. [illegible] BASE CASE FLY ASH ALKALI PROCESS - SO_2 - SCRUBBING

Item	Units required	Description	Source	Unit cost, $	Total cost, $
1. Absorber tower	2	40 ft dia. x 123 ft steel side, carbon steel, lined	CEA	250,500	[illegible]
2. Absorber recycle tank	2	Capacity 450,000 gals 40 ft dia., carbon steel, lined	CEA		
3. Agitator, absorber recycle tank	2	Impeller 120 in., 30 RPM 100 HP, lined	Chemineer		
		Costs, Items 2 & 3		150,000	[illegible]
4. Mesh tray	2	Material 316LL, SS, bubbler tray with supports & nozzles, spray headers, piping and supports			
5. Mist eliminator		4 pass chevron type, with supports, nozzles, spray headers			
		Costs, Items 4 & 5		435,250	852,500
6. Absorber recycle pumps	10	Capacity 15,200 GPM 150 ft TDH, carbon steel rubber lined, with motor	A.S.H. Pumps	50,000	450,000
7. Tray recycle tank	2	Capacity 12,500 gals 14 ft dia. x 12 ft high carbon steel, lined	CEA		

(Continued)

TABLE 27-c. (continued)

Item	Units required	Description	Source	Unit cost, $	Total cost, $
8. Agitator, tray recycle tank	2	S.A.P., carbon steel, rubber lined	Philadelphia Gear, Inc.		
		Costs, items 7 & 8		[illegible]	[illegible]
9. Pumps, tray recycle	4	Capacity 4150 GPM 120 ft TDH, 200 HP carbon steel, lined	Worthington Pumps, Inc.	15,500	62,000
10. Tray thickener tank	1	Capacity 80,000 gals, 40 ft dia. x 12 ft steel side, concrete lined	CEA Sanderson & Porter (S&P)		
11. Agitator, tray thickener tank	1	2 HP, 24 in. rake arms, with motor	Eimco		
		Costs, items 10 & 11		150,000	150,000
12. Tray thickener overflow tank	1	Capacity 11,000 gals 12 ft. dia. x 13 ft high carbon steel, lined	CEA	6,000	6,000
13. Pumps, tray sprays	2	Capacity 1270 GPM 230 ft TDH, 150 HP carbon steel, lined	Worthington Pumps, Inc.	17,500	35,000
14. Pumps, mist eliminator sprays	2	Capacity 15,970 GPM 170 ft TDH, 125 HP carbon steel, lined	Worthington Pumps, Inc.	16,000	32,000
		SUBTOTAL			2,570,586

TABLE 27-4. [illegible]
PROCESS - [illegible]

Item	Units required	Description	Source	Unit cost, $	Total cost, $
1. Main thickener tank	1	Capacity 1,[illegible],000 gals 130 ft dia. x 15 ft steel side, concrete lined	SBP CEA		
2. Agitator, main thickener tank	1	10 HP, 300,000 ft-lb torque	Eimco		
		Costs, Items 1 & 2		[illegible],000	[illegible],000
3. Pumps, main thickener underflow	2	Capacity 450 GPM, 70 ft TDH, 25 HP	Worthington Pumps, Inc.	3,500	7,000
4. Main thickener overflow tank	1	Capacity 11,000 gals 13 ft dia. x 13 ft high, carbon steel, lined	CEA	9,000	9,000
5. Pumps, main thickener overflow	2	Capacity 1112 GPM 62 ft TDH, lined	Worthington Pumps, Inc.	4,600	9,200
6. Pumps, tray thickener underflow	2	Capacity 7.7 GPM 47 ft TDH	Barr-Oliver	3,000	6,000
7. Vacuum filter	1	Capacity 520 ft² 12 ft dia. x 14 ft length	Eimco	272,000	272,000
		SUBTOTAL			1,[illegible],700

TABLE 27-e. [illegible]
PROCESS - HEAT

Item	Units required	Description	Source	Unit cost, $	Total cost, $
1. Reheat mixing chamber	2	Nozzel & jet nozzles	CEA	[illegible]	[illegible]
2. Reheater damper control & motor	2	Butterfly damper 48 in. dia. I.D.	Hamilton	20,400	40,800
		SUBTOTAL			240,800

TABLE 27-4. [illegible]

	Item	Units required	Description	Source	Unit cost, $	Total cost, $
1.	Fan, booster with motor	2	Capacity 1,000,000 ACFM at 30 in. H$_2$O adjustable pitch	Buffalo Forge	725,000	1,450,000
2.	Scrubber inlet damper	2	30 ft x 30 ft carbon steel with motor and controller	Hamilton	113,000	226,000
3.	Scrubber bypass damper	2	30 ft x 30 ft carbon steel with motor actuator	American Vent & Awning	42,500	85,000
4.	Scrubber outlet damper system	2	17 ft dia. SS, with motor & controller	Hamilton	134,000	268,000
			SUBTOTAL			2,029,000

[redacted]

[redacted]

[redacted]

TABLE [illegible]. [illegible]
PROCESS - SERVICE FACILITIES

Item	Units required	Description	Source	Unit cost, $	Total cost, $
1. Buildings		Fly ash slurry tank building	SP		[illegible]
		Pump house			[illegible]
		Vacuum filter building			[illegible]
2. Miscellaneous piping and roads			SP		[illegible]
		TOTAL			[illegible]

TABLE 27-1. [illegible]

	Item	Units required	Description	Source	Unit cost, $	Total cost, $
1.	Excavations & foundations			[illegible]		
2.	Reactor			[illegible]		[illegible]
3.	Fans & ductwork			[illegible]		[illegible]
4.	Thickener & clarifier tunnels & foundations			[illegible]		[illegible]
5.	Buildings and equipment			[illegible]		[illegible]
6.	Sludge storage			[illegible]		[illegible]
7.	Lake water storage tank			[illegible]		[illegible]
8.	Ductwork and manholes (except for L.W. storage tank)			[illegible]		[illegible]
9.	Ductwork - lake water storage			[illegible]		[illegible]
			[illegible]			[illegible]

7. Liquid-to-gas (L/G) ratio of 80 gal/1000 acf (saturated).

8. Off-site sludge disposal in strip mine approximately one mile from site.

9. Fixed investment and operational cost calculations are based on 1976 dollars.

A summary of the estimated fixed investment for the 100 MW, 500 MW base case, and the 1000 MW unit are shown in Tables 28, 29, and 30, respectively. The fixed investment for the fly ash alkali process is about 2-3 pct higher than an equivalent lime system. The increased cost is attributed to the fly ash system, to larger pumps required for high liquid-to-gas (L/G) ratios, and to larger pipes and tanks required for handling the increased amount of solids (9).

The total average annual operating costs for a 100 MW, 500 MW base case, and a 1000 MW system are shown in Tables 31, 32, and 33. Lifetime annual operating costs for the 500 MW base case are shown in Table 34. The operating costs were calculated using a worst case coal sulfur content of 1.3 pct. Under these conditions, addition of supplemental lime is required and operating costs would be at a maximum. In addition to the initial design and cost assumptions, the following was also assumed: 1) mole ratio of lime CaO to absorbed SO_2 is 0.74; and 2) fly ash CaO to absorbed SO_2 mole ratio is 0.26.

A substantial savings in raw material costs is realized by utilizing fly ash alkali. Table 35 shows a comparison of raw material costs for the fly ash alkali process and an equivalent lime system for a 0.75 pct and a 1.3 pct coal sulfur content. The calculations indicate the raw material cost for an equivalent lime system operating on a 1.3 pct sulfur coal would be about 26 pct more than the fly ash alkali process. When the fly ash alkali process is operating on a 0.75 pct sulfur coal, all CaO alkali can be provided by the fly ash.

Calculations on scrubber unit operating costs for the fly ash alkali process are shown in Table 36. The figures for 1.3 pct coal sulfur are based on total operating costs presented in Tables 31, 32, and 33. Figures for 0.75 pct coal sulfur assume no supplemental lime requirements.

TABLE 28. SUMMARY OF ESTIMATED FIXED INVESTMENT FOR A 100 MW FLY ASH ALKALI PROCESS*

Item	Investment, $	Percent of subtotal direct investment
1. Lime system (storage hopper, weigh feeder, slaker, pumps and tanks, agitator)	451,000	1.1
2. Fly ash system (storage hopper, dust collector, weigh feeder, agitator, tank, pumps)	82,400	1.8
3. Sulfur dioxide scrubber (1 scrubber, wash tray, mist eliminators, pumps, agitators, all vessels)	650,000	12.5
4. Solids disposal (filter, thickener pumps, agitators)	208,000	4.0
5. Reheat (mixing chamber, damper, control & motors)	52,000	1.0
6. Gas handling (2 fans, inlet dampers, outlet dampers)	364,000	7.0
7. Structural (structural steel, piping, valves, supports, ducting)	884,000	17.0
8. Instrumentation (all necessary process & flow instruments)	208,000	4.0
9. Cost for erection (items 1-8, craft labor, rentals & consumables, field office)	1,378,000	26.5
10. Utilities (instrument air generation and supply system, distribution system for obtaining process water, electrical switchgear)	520,000	10.0
11. Service facilities (building, shops, stores, site development, roads, walkways)	457,600	8.8

(Continued)

TABLE 28. (continued)

Item	Investment, $	Percent of subtotal direct investment
12. Excavation and foundation	374,400	7.2
Subtotal direct investment	5,200,000	100.0
13. Architect - Engineers design and supervision fee	312,000	6.0
14. Architect - Engineers construction management fee	364,000	7.0
15. Investor's costs	104,000	2.0
16. Contingency	260,000	5.0
Subtotal fixed investment	6,240,000	120.0
17. Allowance for spare parts	260,000	5.0
18. Interest during construction	520,000	10.0
Total capital investment	7,020,000	135.0

* Basis:
Off-site disposal approximately 1 mile from site.
Project beginning early 1975, ending mid-1977.
Minimum in-process storage; only pumps are spared.
Investment requirements for disposal of ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.
Items previously noted.

TABLE 29. SUMMARY OF ESTIMATED FIXED INVESTMENT FOR A 500 MW BASE CASE FLY ASH ALKALI PROCESS*

Item	Investment, $	Percent of subtotal direct investment
1. Lime system (storage hopper, weigh feeder, slaker, pumps and tanks, agitator)	189,600	0.8
2. Fly ash system (storage hopper, dust collector, weigh feeder, agitator, tank, pumps)	244,400	1.2
3. Sulfur dioxide scrubber (2 scrubbers, wash tray, mist eliminators, pumps, agitators, all vessels)	2,578,500	10.7
4. Solids disposal (filter, thickener, pumps, agitators)	1,034,500	4.3
5. Reheat (mixing chamber, damper, control & motors)	240,800	1.0
6. Gas handling (2 fans, inlet dampers, bypass dampers, outlet dampers)	2,029,000	8.5
7. Structural (structural steel, piping, valves, supports, ducting)	4,260,000	17.7
8. Instrumentation (all necessary process & flow instruments)	1,018,000	4.2
9. Cost for erection (items 1-8, craft labor, rentals & consumables, field office)	6,025,000	25.1
10. Utilities (instrument air generation and supply system, distribution system for obtaining process water, electrical switchgear)	2,540,000	10.6
11. Service facilities (building, shops, stores, site development, roads, walkways)	2,130,000	8.8

(Continued)

TABLE 29. (continued)

	Item	Investment, $	Percent of subtotal direct investment
12.	Excavation and foundation	1,750,000	7.1
	Subtotal direct investment	24,039,500	100.0
13.	Architect - Engineers design and supervision fee	1,442,000	6.0
14.	Architect - Engineers construction management fee	1,683,000	7.0
15.	Investor's fee	481,000	2.0
16.	Contingency	1,202,000	5.0
	Subtotal fixed investment	28,847,500	120.0
17.	Allowance for startup and modification	1,202,000	5.0
18.	Interest during construction	2,404,000	10.0
	Total capital investment	32,453,500	135.0

* Basis:
Off-site disposal approximately 1 mile from site.
Project beginning early 1975, ending mid-1977.
Minimum in-process storage; only pumps are spared.
Investment requirements for disposal of ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.
Items previously noted.

TABLE 30. SUMMARY OF ESTIMATED FIXED INVESTMENT FOR A 1000 MW FLY ASH ALKALI PROCESS*

Item	Investment, $	Percent of subtotal direct investment
1. Lime system (storage hopper, weigh feeder, slaker, pumps and tanks, agitator)	451,000	1.1
2. Fly ash system (storage hopper, dust collector, weigh feeder, agitator, tank, pumps)	492,000	1.2
3. Sulfur dioxide scrubber (4 scrubbers, wash tray, mist eliminators, pumps, agitators, all vessels)	4,100,000	10.0
4. Solids disposal (filter, thickener pumps, agitators)	1,640,000	4.0
5. Reheat (mixing chamber, damper, control & motors)	1,025,000	2.5
6. Gas handling (2 fans, inlet dampers, bypass dampers, outlet dampers)	3,403,000	8.3
7. Structural (structural steel, piping, valves, supports, ducting)	7,544,000	18.4
8. Instrumentation (all necessary process & flow instruments)	1,640,000	4.0
9. Cost for erection (items 1-8, craft labor, rentals & consumables, field office)	10,045,000	24.5
10. Utilities (instrument air generation and supply system, distribution system for obtaining process water, electrical switchgear)	4,100,000	10.0
11. Service facilities (building, shops, stores, site development, roads, walkways)	3,690,000	9.0

(Continued)

TABLE 30. (continued)

Item	Investment, $	Percent of subtotal direct investment
12. Excavation and foundation	2,870,000	7.0
Subtotal direct investment	41,000,000	100.0
13. Architect - Engineers design and supervision fee	2,460,000	6.0
14. Architect - Engineers construction management fee	2,870,000	7.0
15. Investor's costs	820,000	2.0
16. Contingency	2,050,000	5.0
Subtotal fixed investment	49,200,000	120.0
17. Allowance for spare parts	2,050,000	5.0
18. Interest during construction	4,100,000	10.0
Total capital investment	55,350,000	135.0

* Basis:
Off-site disposal approximately 1 mile from site.
Project beginning early 1975, ending mid-1977.
Minimum in-process storage; only pumps are spared.
Investment requirements for disposal of ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.
Items previously noted.

TABLE 31. TOTAL AVERAGE ANNUAL OPERATING COST FOR A 100 MW FLY ASH ALKALI PROCESS*

Item	Annual quantity	Unit cost, $	Total annual cost, $
Direct Costs			
Raw Material:			
Lime	10.0 M tons	40.00/ton	398,200
Subtotal raw material			398,200
Conversion Costs			
Operating labor & supervision	8,990.0 man-hr	10.00/man-hr	89,900
Utilities:			
Steam	482,790.0 M lb	.00/M lb	0
Process water	64,630.0 M gal	.09/M gal	5,800
Electricity	12,073,490.0 KWH	.02/KWH	241,700
Maintenance:			
Labor and material			165,400
Analyses	910.0 hr	2.00/hr	1,800
Subtotal conversion costs			504,600
Subtotal direct costs			902,800
Indirect Costs			
Depreciation			364,700
Cost of capital and taxes, 8.25% of undepreciated investment			939,600
Insurance & interim replacements, 1.17% of fixed investment			133,300
Overhead:			
Plant, 10.0% of conversion costs less utilities			25,700
Administrative, research & service, 0.0% of operating labor & supervision			0
Subtotal indirect costs			1,463,300
Total annual operating cost			2,366,100

* Basis: Remaining life of powerplant is 30 years.
Coal burned is 464,000 ton/yr, 6400 Btu/lb, 10,000 Btu/KWH.
Items previously noted.

TABLE 32. TOTAL AVERAGE ANNUAL OPERATING COST FOR A 500 MW BASE CASE FLY ASH ALKALI PROCESS*

Item	Annual quantity	Unit cost, $	Total annual cost, $
Direct Costs			
Raw Material:			
Lime	49.8 M tons	40.00/ton	1,991,000
Subtotal raw material			1,991,000
Conversion Costs			
Operating labor & supervision	20,110.0 man-hr	10.00/man-hr	201,100
Utilities:			
Steam	2,413,940.0 M lb	.00/M lb	0
Process water	323,170.0 M gal	.09/M gal	29,100
Electricity	52,247,390.0 KWH	.02/KWH	1,044,900
Maintenance:			
Labor and material			447,800
Analyses	2,810.0 hr	2.00/hr	5,600
Subtotal conversion costs			1,728,500
Subtotal direct costs			3,719,500
Indirect Costs			
Depreciation			987,500
Cost of capital and taxes, 8.25% of undepreciated investment			2,679,000
Insurance & interim replacements, 1.17% of fixed investment			365,700
Overhead:			
Plant, 10.0% of conversion costs less utilities			68,500
Administrative, research & service, 0.0% of operating labor & supervision			0
Subtotal indirect costs			3,997,700
Total annual operating cost			7,717,200

* Basis: Remaining life of powerplant is 30 years.
Coal burned is 2,324,200 ton/yr, 8400 Btu, 10,000 Btu/KWH.
Items previously noted.

TABLE 33. TOTAL AVERAGE ANNUAL OPERATING COST FOR A 1000 MW FLY ASH ALKALI PROCESS*

Item	Annual quantity	Unit cost, $	Total annual cost, $
Direct Costs			
Raw Material:			
Lime	99.6 M tons	40.00/ton	3,982,000
Subtotal raw material			3,982,000
Conversion Costs			
Operating labor & supervision	28,440.0 man-hr	10.00/man-hr	284,400
Utilities:			
Steam	4,827,000.0 M lb	.00/M lb	0
Process water	646,350.0 M gal	.09/M gal	58,200
Electricity	102,746,820.0 KWH	.02/KWH	2,054,900
Maintenance:			
Labor and material			808,100
Analyses	4,570.9 hr	2.00/hr	9,100
Subtotal conversion costs			3,214,700
Subtotal direct costs			7,196,700
Indirect Costs			
Depreciation			1,781,900
Cost of capital and taxes, 8.25% of undepreciated investment			4,652,400
Insurance & interim replacements, 1.17% of fixed investment			659,801
Overhead:			
Plant, 10.0% of conversion costs less utilities			110,200
Administrative, research & service, 0.0% of operating labor & supervision			0
Subtotal indirect costs			7,204,300
Total annual operating cost			14,401,000

* Basis: Remaining life of powerplant is 30 years.
Coal burned is 4,648,400 ton/hr, 8400 Btu/lb, 10,000 Btu/KWH.
Items previously noted.

[illegible]

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]								
[illegible]								
[illegible]								

TABLE 35. COMPARISON OF RAW MATERIAL OPERATING COSTS FOR LIME SCRUBBING VERSUS FLY ASH ALKALI SCRUBBING*

	1.3 pct (coal)-S		0.75 pct Coal-S	
	Equivalent lime process	Fly ash alkali process (lime and fly ash)	Equivalent lime process	Fly ash alkali process (lime and fly ash)
100 MW Unit	$ 538,100	$ 398,200	$ 290,900	-0-
500 MW Unit	2,691,000	1,991,000	1,455,000	-0-
1000 MW Unit	5,381,000	3,982,000	2,909,000	-0-

* Basis: 15 pct flue gas bypass for reheat,
85 pct SO_2 removal in absorber tower,
1.0 CaO-total to absorbed SO_2 mole ratio (0.74 mole lime CaO).

TABLE 36. SCRUBBER UNIT OPERATING COSTS FOR THE FLY ASH ALKALI PROCESS*

	1.3 pct Coal-Sulfur			0.75 pct Coal-Sulfur		
	100 MW	500 MW	1000 MW	100 MW	500 MW	1000 MW
Coal burned, $/ton	5.09	5.32	5.10	4.23	2.46	2.24
Mills/KWH	3.98	2.59	2.42	3.31	1.93	1.75
Cents/10^6 Btu input	39.7	25.9	24.2	33.1	19.3	17.5

* Includes depreciation, cost of capital and taxes, insurance, and plant overhead.

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APPENDIX A

TABLE A-1. SUMMARY OF RESULTS FROM THE DESIGN AND OPERATING TEST SERIES CONDUCTED AT L/G 60*

Add rate ton/hr		SO_2-In	SO_2-Out	Pct removal		Recycle slurry
Fly Ash	Lime	ppm-dry	ppm-dry	System	Tower	pH
16.4	-0-	1094	920	21	63.5	3.9
16.3	-0-	1121	402	64.1	75.4	3.9
16.6	-0-	1036	469	55	64.7	3.9
15.6	-0-	962	435	55	64.7	3.9
25.4	-0-	975	301	69.1	81.3	4.7
25.2	-0-	998	305	69.4	81.7	4.9
14.7	9.9	1880	620	67	78.8	6.5
15.1	8.5	1660	503	68.6	80.7	6.6
17.0	4.2	1880	507	73	85.9	6.7
16.2	7.3	1887	598	68.4	80.1	6.7
25.9	6.4	1890	537	71.6	84.2	6.8
26.6	7.1	1883	540	70.5	82.9	6.8

* L/G based on gallons of recycle slurry per 1000 acf saturated flue gas.

TABLE A-2. SUMMARY OF RESULTS FROM THE DESIGN AND OPERATING TEST SERIES CONDUCTED AT L/G 80*

Add rate ton/hr		SO_2-In	SO_2-Out	Pct removal		Recycle slurry
Fly ash	Lime	ppm-dry	ppm-dry	System	Tower	pH
16.5	-0-	991	320	68	80	4.1
16.2	-0-	1120	252	77.5	91.2	3.9
16.8	-0-	1120	362	67.7	79.7	5.4
24.8	4.5	1096	217	80.2	94.4	5.4
27.1	1.8	1104	183	83.4	96.1	7.0
16.9	9.6	1984	413	80.1	94.2	6.6
15.4	10.3	1860	379	79.2	93.2	6.6
16.4	7.5	1935	583	69.9	82.2	6.3
16.2	7.5	1863	490	73.9	86.9	6.8
17.2	7.8	1887	386	79.5	93.5	6.8
16.7	7.3	1873	400	78.6	92.4	7.1
24.5	8.0	1887	365	81.2	95.5	6.3
25.2	8.1	1352	380	79.5	93.5	7.2

* L/G based on gallons of recycle slurry per 1000 acf saturated flue gas.

Job Number	File Number	Rec'd	Dk'd	FDM 1" FDM 2"	Lam Hrs.	SHOP DRAWINGS Sub.	Appr.	To Shop	Lam Sch.	Deck Sch.	REMARKS